March 4, 2016

Via electronic mail and U.S. mail

Department of Conservation, Division of Oil, Gas & Geothermal Resources
801 K Street, MS 24-02
Sacramento, CA 95814
ATTN: UIC Discussion Draft

UIC.Regulations@conservation.ca.gov

Dear Sir/Madam:

Re: Notice of Pre-Rulemaking Draft Regulations

We thank the Department of Conservation, Division of Oil, Gas and Geothermal Resources ("DOGGR") for the opportunity to comment on Pre-Rulemaking Draft Regulations circulated on January 21, 2016 ("Draft Regulations"). Given the inherent and well-documented risks of oil and gas, no amount of regulations will eliminate the dangers posed by Class II wells. Already, the state's groundwater supplies have been contaminated as a result of widespread illegal injection activity, which DOGGR refuses to address. Thousands of Class II wells that may be injecting into protected aquifers continue to operate while DOGGR waits for its slow-paced reviews to conclude. The best way for DOGGR to meet its obligation to protect public health and safety and the environment is for DOGGR to prohibit further injection via Class II injection wells.

We are deeply concerned by the Draft Regulations. In our comments on the Discussion Paper circulated prior to these Draft Regulations, we asserted that if DOGGR is serious about its role as a regulator, it will approach this rulemaking from the perspective that the protection of California's groundwater resources is of paramount concern, and takes precedence over the convenience of the oil and gas industry. The State Oil and Gas Supervisor has a duty to

Clare Lakewood, Climate Staff Attorney . 1212 Broadway, Suite 800 . Oakland, CA 94612
Phone: 510-844-7100 x 321 . *Fax:* 510-844-7150 . *clakewood@biologicaldiversity.org*

"supervise the drilling, operation, maintenance, and abandonment of wells and the operation, maintenance, and removal or abandonment of tanks and facilities attendant to oil and gas production … within an oil and gas field, so as to prevent, as far as possible, damage to life, health, property and natural resources; damage to underground oil and gas deposits from infiltrating water and other causes; loss of oil, gas or reservoir energy, and damage to underground and surface waters suitable for irrigation or domestic purposes by the infiltration of, or the addition of, detrimental substances."[1] Rather than finally fulfill its role as regulator, however, DOGGR has, under the guise of regulatory reform, circulated Draft Regulations that in fact *loosen* and *lessen* the standards and scrutiny that apply to Class II underground injection wells – standards and scrutiny that include regulations recently found to be the laxest in the United States.[2] The Draft Regulations do not adequately protect public health and safety or the environment.

DOGGR has a history of failing to take its legal obligations seriously, of ignoring laws and risking our water resources for the convenience of the oil industry, and as a result, has allowed scores of aquifers to be contaminated by Class II injection wells. These Draft Regulations demonstrate that this mindset remains.

I. EXECUTIVE SUMMARY

a) DOGGR must not, under the guise of updating its insufficient and unsafe existing regulations, attempt to authorize illegal steam injection above fracture gradient.

b) The proposed definition of "freshwater" would leave USDWs at risk of contamination.

c) If promulgated, these Draft Regulations would violate federal law.

d) The Draft Regulations do not provide for the public notice and comment procedures that DOGGR committed to when it took on administration of California's Class II well program.

e) The Draft Regulations inexplicably fail to address the well-documented risks of induced seismicity from wastewater injection and enhanced oil recovery.

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[1] Public Res. Code § 3106(a).

[2] Zirogiannis, N, et al. State regulation of unconventional gas development in the U.S.: An empirical evaluation. Energy Research & Social Science 11: 142-154 (2016), Fig. 5.

f) The proposed injection fluid testing processes are too infrequent, do not test for a sufficient range of toxic chemicals which may be present in the fluid, and contain loopholes that allow operators to avoid providing data.

g) Groundwater monitoring obligations must be imposed on operators.

h) The Project Approval Process lacks clarity and transparency, and fails to collect important data.

i) DOGGR must ensure that it complies with its legal obligations to notify EPA of the rulemaking process and the possible content of the regulations.

II. DOGGR MAY NOT AUTHORIZE ILLEGAL STEAM INJECTION ABOVE THE FORMATION FRACTURE GRADIENT

DOGGR is developing these regulations in the context of expert reports criticizing regulation of the UIC Program in California,[3] the revelations of widespread violations of the UIC Program, and demands by the EPA[4] and the California Legislature[5] that DOGGR comply with federal law and take the necessary action to protect the community from the dangers posed by UIC projects. Staggeringly, DOGGR has responded by proposing to legalize a dangerous oil and gas production practice that is currently illegal under its existing regulations. Currently, the Public Resources Code prohibits injection above fracture grade.[6] Draft Regulations section 1724.10(i) would allow an operator to inject at pressures high enough to break up the formation rock if the operator "demonstrates conclusively" that the fluid will remained confined to the injection zone. This is an attempt to authorize illegal ongoing steam-injection practices that state officials have admitted fracture the formation. It is difficult to believe that in the midst of all the scrutiny DOGGR is facing because of its lax approach to public and environmental safety, it is

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[3] Horsley Witten Group, California Class II Underground Injection Control Program Review (Jun. 2011) ("Horsley Witten Report").

[4] Diamond, Jane, Director, Water Division, US EPA Region IX, Letter to Steven Bohlen, State Oil and Gas Supervisor, DOGGR (Dec. 22, 2014).

[5] Joint Hearing Senate Natural Resources and Water Committee and Senate Environmental Quality Committee (Mar. 10, 2015), p. 6 (Statement of Chairman Wieckowski: "However, what assurances do I and my colleagues in the legislature have that DOGGR will not continue to ignore state and federal law and regulations? DOGGR has serious credibility and performance problems. I will be listening today for its plans and pledge to continue oversight efforts.")

[6] Pub. Res. Code § 1724.10(i): Maximum allowable surface injection pressure shall be less than the fracture pressure.

proposing to weaken current law and *increase* the risk to communities and the environment, by attempting to authorize illegal steam injections above fracture grade.

Steam injection above fracture gradient carries the risk of sudden development of dangerous sinkholes, surface oil and chemical eruptions and spills, and subsurface oil and chemical migrations and seepages, and causes land subsidence. One of the greatest risks of steam injection above the fracture gradient is that it may create subsurface conduits through which oil, water and steam can migrate, resulting in dangerous surface uplift and subsidence. Once formed and expressed, subsequent steam and fluids may continue to migrate through that pathway even if subsequent injections are below the fracture pressure.[7] This is particularly concerning given that, as a consequence of groundwater depletion and the drought, water supply wells are being drilled deeper, sometimes even deeper than disposal wells, and therefore may be endangered by induced conduits and fluid migration related to flooding and disposal wells.[8]

Not only are the proposed regulations dangerous, they are also inconsistent with the federal law regulations governing underground injection of fluids.[9] As DOGGR well knows, it administers its Class II UIC Program pursuant to section 1425 of the Safe Drinking Water Act.[10] In 1982, the U.S. EPA and the California Division of Oil and Gas (as it then was) entered into an Memorandum of Agreement ("MOA") setting out how the Division (later renamed DOGGR) would administer the Class II portion of the U.S. EPA's underground injection control program ("UIC Program").[11] In 1983, the U.S. EPA delegated to California state regulators primary authority, or "primacy," to enforce the law governing Class II wells (those used for injection of fluids associated with oil and gas production, including disposal of toxic wastewater from hydraulic fracturing).[12] Section 1421(b) of the Safe Drinking Water Act demands that regulations for state UIC Programs require applicants for an injection permit to "satisfy the State that the

[7] Department of Conservation, Division of Oil, Gas and Geothermal Resources, Report of Occurrences: The Chevron Fatality Accident June 21, 2011 (May, 2012) ("Chevron Fatality Accident Report"), p. 10, *available at* http://psbweb.co.kern.ca.us/UtilityPages/Planning/EIRS/mckittrick_landfill/Vol5/CA%20DOC%20DOGGR%20Well%2020%20--Report%20re%20Chevron%20Fatality%206-21-11%20%285-4-2012%29.pdf.
[8] See, for instance, Department of Conservation, Division of Oil, Gas and Geothermal Resources, Notice to Operators: A Strategy for Produced Water (Sep. 9, 2015), p. 1: "[M]any injection wells used for waste disposal today are relatively shallow. The average depth of disposal wells in the state is … a depth that now is shallower than some water supply wells."
[9] 40 Fed. Reg. § 144 *et seq.* ("Federal Regulations").
[10] 42 U.S.C. § 300h-4.
[11] California Division of Oil and Gas – US EPA Region IX , Underground Injection Control Program Memorandum of Agreement, (Sep. 28, 1982) ("UIC Program MOA"), attached as Appendix A.
[12] *Id.*

underground injection will not endanger drinking water sources."[13] Injection above the fracture gradient increases the risk that drinking water sources will be contaminated.[14] Allowing drinking water sources to be endangered by allowing injection above fracture gradient therefore puts the state in violation of its obligations under the Safe Drinking Water Act.

III. Proposed Areas of Review Are Weaker than Existing Regulations and Directly Contrary to the Recommendations of EPA

We are very concerned that the Draft Regulations propose a default AOR for cyclic steam wells of merely 300 feet. If implemented, California would be the only state to permit AORs for Class II wells of less than a quarter-mile.[15] A 300-foot AOR radius is also inconsistent with federal regulations, which require a minimum fixed radius of a quarter-mile unless an approved mathematical model is used to determine the ZEI.[16] Furthermore, it is demonstrably unsafe. In the investigation into the June, 2011, fatality resulting from a surface expression near Chevron's steam injection wells in the Midway-Sunset field, it is reported that Chevron had implemented a 500-foot radius restriction on steam injection around the area where surface expressions had been occurring.[17] That is, the operator itself considered a cyclic steam well to be capable of influencing geologic features at least 500 feet away. Tilt meter data for the 10 days prior to the fatality attributed events at the surface expression site to various wells that were located more than 500 feet away.[18] Ultimately DOGGR itself issued orders prohibiting steam injection within 800 feet of the surface expression.[19]

In this period of historic drought, it is vitally important that no USDW be put at risk. DOGGR must take its obligations as a regulator seriously, and require ZEI calculations for all Class II injection projects.

Any amendments to California's law relating to the UIC Program and Class II wells must be consistent with the SDWA and the Federal Regulations. The Federal Regulations provide that

[13] 42 U.S.C. §300h(b)(1)(B).
[14] U.S. Environmental Protection Agency, *Hydraulic Fracturing Drinking Water Assessment* (June, 2015), ES-6.
[15] Panchal, Yahesh Jitendra, "Comparison of class II injection well area of review requirements with area of evaluation for hydraulically fractured wells." *Masters Theses*, Paper 5367 (2013), pp. 13-15.
[16] 40 C.F.R. § 146.6.
[17] Chevron Fatality Accident Report, p. 3.
[18] *Id*, pp. 5-6.
[19] *Id*, p. 8.

States need not implement provisions identical to the provisions with which State programs must comply, but that provisions implemented by a State must establish requirements "at least as stringent as the corresponding listed provisions. While States may impose more stringent requirements, they may not make one requirement more lenient as a tradeoff for making another requirement more stringent; for example, by requiring that public hearings be held prior to issuing any permit while reducing the amount of advance notice of such a hearing."[20] Accordingly, if the Draft Regulations are not in conformance with, or are less stringent than, the specified provisions of the Code of Federal Regulations, DOGGR is in violation of federal law.

IV. Definition of Freshwater is Unlawful

a. Definition of Freshwater Leaves USDWs Unprotected

Section 1421(b)(1) demands that states with primary enforcement responsibility require that applicants for an injection permit demonstrate that the underground injection will not endanger "drinking water sources."[21] That term is not defined in the Safe Drinking Water Act.

The regulations define "underground source of drinking water" as:

an aquifer or its portion:

(a) (1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer.[22]

In contrast, "freshwater" is defined in the Draft Regulations as "water than contains 3,000 TDS or less."[23]

b. The Definition of Freshwater Leaves USDWs at Risk from Oil and Gas Activities

[20] 40 C.F.R. § 145.11(b)(1).
[21] 42 U.S.C. 300h(b)(1).
[22] 40 C.F.R. § 144.3
[23] Draft Regulations § 1720.1(d). "TDS" is not defined in the Draft Regulations, but is commonly understood to mean , in this context, "total dissolved solids." The definition fails to provide a unit of measurement that would make the quantity of total dissolved solids meaningful. The usual unit of measurement, and that which is used in regulations made pursuant to the Safe Drinking Water Act regulations, is milligrams per liter (mg/L).

The overly-narrow proposed definition of "freshwater" also leaves USDWs at risk of contamination or endangerment by non-Class II wells. 14 C.C.R § 1722.2 requires that onshore wells (of any kind) shall have a casing "designed to provide anchorage for blowout prevention equipment and to seal off fluids and segregate them for the protection of all oil, gas, and freshwater zones." Using the definition of "freshwater" in the Draft Regulations, there would no obligation to have a casing designed to segregate fluids from USDWs with more than 3,000 mg/L TDS, leaving them at risk of contamination. Likewise, intermediate casings may be required "for protection of oil, gas and freshwater zones."[24] Intermediate casings are not required for USDWs. Cement casing must be used to fill the annular space of a wall to at least 100 feet "above the base of the freshwater zone." No such protection is provided for USDWs. The plugging standards for freshwater protection set out in 14 C.C.R § 1723.2 would not be apply to USDWs, leaving them at risk of contamination from saltwater.

c. <u>"Freshwater" Should Be Defined so as to Protect California's Sources of Drinking Water</u>

The only way in which DOGGR can be assured of protecting USDWs to the extent required by the Safe Drinking Water Act and its attendant regulations, as well as providing practical protection of USDWs against the dangers posed by other oil and gas activities, is to adopt the definition of a USDW for the term "freshwater" as it is used in Title 14 of the California Code of Regulations.

However, DOGGR need not limit its definition of "freshwater" to only the federal definition of USDW, and waters protected under the UIC program need not be limited to those defined as "freshwater." Section 1425 of the SDWA[25] does not prohibit a state from enacting regulations that are more stringent than those set out in the SDWA. DOGGR should protect underground water in a manner that adequately takes into account current and future water crises in California. Doing so requires protection of water certainly with more than 3,000 mg/l TDS, and even more than 10,000 mg/l TDS.

California is currently in the fourth year of a historic drought, and communities are more dependent than ever on underground water resources. It is vital, therefore, that DOGGR act to

[24] Pub. Res. Code § 1722.3(d).
[25] 42 U.S.C. § 300h-4.

ensure our aquifers are protected from the toxic waste generated by oil and gas production processes. Overall, 85 percent of California's public water systems depend on groundwater for at least part of their drinking water, and smaller urban and rural areas depend entirely on groundwater.[26] California's reliance on groundwater increases during times of drought and will continue to increase with the growing demand from municipal, agricultural, and industrial sources, especially as surface water availability changes as a result of climate change and drought.[27] The most recent data available as of October 2014 shows that groundwater levels have decreased in many basins throughout the state since spring 2013, and more notably since spring 2010; basins with notable decreases in groundwater levels are in the Sacramento River, San Joaquin River, Tulare Lake, San Francisco Bay, Central Coast, and South Coast hydrologic regions.[28] Indeed, there is precedent on the Central Coast for a scenario in which drought causes a major increase in reliance on groundwater supplies: during the last major drought in the late 1980s, the City of San Luis Obispo began pumping groundwater for the first time in history, and by 1990 it received 40% of its water from groundwater.[29]

The historic drought has fundamentally changed the way Californians use water. It has prompted mandatory water restrictions, new wells that are deeper and that tap into previously unused aquifers, and the serious consideration of alternative water purification technologies. For instance, just this week, the Carlsbad desalination plant, able to treat water of 33,500 mg/L TDS,[30] went online.[31] At the same time, desalination is becoming a cheaper and more efficient

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[26] State Water Resources Control Board, Report to the Legislature: Draft Communities that Rely on Contaminated Ground Water (Jan. 2013) ("SWRCB, 2013"), p. 6.

[27] SWRCB, 2013, p. 6; Memorandum from Howitt et al., UC Davis Center for Watershed Sciences, to California Department of Food and Agriculture (May 31, 2015) ("Howitt, 2015"), *available at:* https://watershed.ucdavis.edu/files/biblio/2015Drought_PrelimAnalysis.pdf.

[28] Cal. Department of Water Resources, "Public Update for Drought Response: Groundwater Basins with Potential Water Shortages, Gaps in Groundwater Monitoring, Monitoring of Land Subsidence, and Agricultural Land Fallowing (Nov. 2014) ("DWR, 2014"), pp. 5, 11 (emphasis added), *available at:* http://water.ca.gov/waterconditions/docs/DWR_PublicUpdateforDroughtResponse_GroundwaterBasins.pdf.

[29] Halverson, Nathan, "What will happen to a sinking California? Just ask San Luis Obispo," *Grist* (June 24, 2015) (Halverson), *available at:* http://grist.org/climate-energy/what-will-happen-to-a-sinking-california-just-ask-san-luis-obispo/.

[30] Dow Water & Process Solutions, Dow Reverse Osmosis Membranes Treat Seawater (Aug. 2015), p. 1.

[31] *See, e.g.,* Fikes, Bradley J., "$1-Billion Desalination Plant, Hailed as Model for State, Opens in Carlsbad," *Los Angeles Times* (Dec. 14, 2015), *available at:* http://www.latimes.com/local/california/la-me-desalination-20151215-story.html.

process. Indeed, the largest desalination plant in the United States is scheduled to come online in 2016.[32]

In the future, state agencies may need to look not just to seawater, but to aquifers previously considered too salty to be usable, as a source of drinking water. The SDWA mandates protection of future drinking water sources as well as current sources. These regulations are more than thirty years old, and water treatment technology has improved dramatically since then, especially as water demand from previously unused groundwater sources has increased due to the drought.[33] Given the potential for desalination and other treatment systems to render what was previously considered unusable water potable, DOGGR should define "freshwater" using protective approach more accurately reflects current technology in water treatment, and the attitude California must take to ensure the future availability of sufficient fresh water during this time of historic drought.

V. THE DRAFT REGULATIONS ARE INCONSISTENT WITH FEDERAL REGULATIONS

California is touted as a leader, nationally and globally, for its "green" approach – protecting communities and ecosystems from the threats posed by dangerous and destructive human activity. Yet these Draft Regulations continue the real legacy of California's government – trading on its "green" reputation while failing to take the necessary action to protect the public from the harms of fossil fuel production. It is deeply concerning that, in its efforts to modernize and address its historic failures, DOGGR has proposed Draft Regulations that are weaker even than the current standards in many regards and weaker than those imposed by federal law.

A. The Permitting Process Is Inconsistent With, and Less Stringent Than What Federal Regulations Require

1. Information Required to Be Provided in Order to Receive a Permit Is Insufficient to Comply with the Federal Regulations

[32] Rogers, Paul, *Nation's Largest Ocean Desalination Plant Goes Up Near San Diego*, San Jose Mercury News, (May 28, 2014), *available at* http://www.mercurynews.com/science/ci_25859513/nations-largest-ocean-desalination-plant-goes-up-near.
[33] Noel, John , *Aquifer Exemptions: A First-Ever Look at the Regulatory Program That Writes off Drinking Water Resources for Oil, Gas, and Uranium Profits*, Clean Water Action/Clean Water Fund (Jan. 2015) ("Noel"), p. 6, *available at* http://www.cleanwateraction.org/files/publications/Aquifer%20Exemptions%20-%20Clean%20Water%20report%201.6.15.pdf

40 CFR § 144.31(e)(7) requires all applicants for Class II wells to include in their application for a permit:

> A topographic map (or other map if a topographic map is unavailable) extending *one mile beyond the property boundaries of the source* depicting the facility and each of its intake and discharge structures; each of its hazardous waste treatment, storage, or disposal facilities; *each well where fluids from the facility are injected underground; and those wells, springs, and other surface water bodies, and drinking water wells listed in public records or otherwise known to the applicant within a quarter mile of the facility property boundary*. (emphasis added)

The Draft Regulations do not require any such map to be included with an application for a Project Approval Letter for an underground injection project. In fact, the Draft Regulations do not require an applicant to provide any map extending beyond the scope of the area of review, which may be as little as 300 feet.[34] The mapping obligations on applicants are therefore far less stringent than those required under federal law, and therefore Californians and their precious drinking water dangerously unprotected.

2. <u>DOGGR's Failure to Issue Draft Permits for Public Comment is Inconsistent with the Federal Regulations and the California Environmental Quality Act (CEQA)</u>

Section 124.6(a) and (d) require the Supervisor to, upon receiving a complete application for an underground injection project, tentatively decide whether to prepare a draft permit or to deny the application. If the Supervisor tentatively decides to approve the application, he or she must prepare a draft permit. Section 124.10(a)(1)(ii) requires the Supervisor to give public notice of the preparation of the draft permit. Section 124.11 provides that any person may submit comments on the permit and may request a public hearing. Comments are required to be considered and answered.[35]

The Draft Regulations do not contain any process for preparation of a draft permit, provision of public notice, opportunity for public comment or response to public comments. Grant of a Project Approval Letter without issuing a draft permit and giving public notice and the

[34] Draft Regulations § 1720.1(a).
[35] 40 C.F.R. §§ 124.11, 124.17, read in conjunction with 40 C.F.R. §§ 145.11(a)(29), (31).

opportunity for public comment is inconsistent with the clear requirements of the Federal Regulations. It is also a less stringent process because it carries less scrutiny. It denies the opportunity for DOGGR to obtain information and opinions from members of the public or persons working in the industry that might provide insight into the appropriateness of the permit or the conditions that should attach. Accordingly, the process in the Draft Regulations is less consultative than that required by federal law. It allows fossil fuel producers, and those disposing of waste from the fossil fuel industry, to avoid public scrutiny of their actions. It denies the public the opportunity to provide input into DOGGR's permitting processes.

The issuance of a UIC permit is a discretionary action subject to CEQA. By failing to articulate when and how DOGGR will comply with CEQA, DOGGR appears to contemplate that it will continue to violate CEQA. This is unacceptable.

B. Fluid Testing Requirements are Inconsistent with, and Less Stringent Than, the Federal Regulations Require

40 CFR section 144.51(j) requires that the permittee retain records of all monitoring information, including "[t]he nature and composition of *all* injected fluids until three years after the completion of any plugging and abandonment procedures…." (emphasis added).

Draft Regulations § 1724.10(d) only requires that a chemical analysis of injected fluids be prepared every two years, whenever the source of injection fluid is changed, or an additional source is introduced. It is entirely conceivable that the nature and composition of injected fluid may change even if the source remains constant, but there is no obligation on an operator to keep records of the changed injection fluid (unless it happens to coincidentally fall on the arbitrary fall-back two year testing schedule). The Draft Regulations are not in conformance with federal law. They clearly impose less stringent fluid composition recording requirements than the requirements of federal law, which demand that operators keep records of "all injected fluids."

Further, the Draft Regulations do not impose any obligations on operators to keep records of the chemical analysis of injected fluids. This is not in conformance with the requirements of the Federal Regulations, and is clearly less stringent than the requirements of those regulations. The result may be that, in the event of a spill or contamination of an aquifer, it is difficult, if not impossible, to hold those responsible accountable for their actions.

VI. DRAFT REGULATIONS VIOLATE THE MOA AND THE 1425 DEMONSTRATION

As set out above, DOGGR administers the UIC Program in California pursuant to section 1425 of the Safe Drinking Water Act. In 1981, DOGGR prepared an Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act ("1425 Demonstration"), as required by 40 C.F.R. § 145.23. The federal EPA and DOGGR subsequently entered a Memorandum of Agreement ("MOA"), as required by 40 C.F.R. § 145.25, in September 1982.[36] EPA approved DOGGR's application for primacy in the regulation of Class II injection wells in March 1983.[37]

A. Lack of Public Notice and Comment Process Violates the MOA

Clause 1(F)(1) of the MOA requires that DOGGR provide "adequate public notice for its proposed actions, as described in the 1425 Demonstration." The MOA requires DOGGR to provide "at minimum" a 15-day public comment period, and to make the non-confidential portions of the project application available for review. Where the Supervisor determines that a public hearing is necessary, public notice shall be provided at least 30 days prior to the public hearing.[38] Additional public notice is required whenever there are substantial changes to an approved project. Substantial changes include "significant increases in injection pressures, change in injection zone, or significant changes in injection fluid." The Draft Regulations make no provision at all for public notice and comment processes.

DOGGR cannot rely on a policy of providing public notice and comment that it does not actually follow. According to the 1425 Demonstration, it is currently "[t]he policy of the division … to publish public notices in major Californian newspapers of wide circulation inviting public review and comment for proposed new underground injection projects, or for substantial changes in the permit conditions of existing projects. Public hearing may be held prior to the issuance of new permits or modifications of existing permits at the discretion of the State Oil and Gas Supervisor."[39] DOGGR's compliance with this obligation is technical, if it is in compliance at all. Few people see the notices posted for three days in the local paper, and comments and

[36] An MOA is required before a State may be granted primacy. *See* 40 C.F.R. § 145.25.
[37] 42 U.S.C. §300h-4(a) (2006); 48 Fed. Reg. 6336.
[38] MOA, Cl. 1(F)(1).
[39] 1425 Demonstration, section R.

hearings occur rarely, if ever.[40] Given DOGGR's history of ignoring its legal obligations entirely or complying with obligations in a manner that discourages public participation, the public has no assurance that DOGGR will here develop a policy that genuinely encourages public participation in the permitting process. The absence of public notice and comment process in the rulemaking must be understood as an intention not to implement any such process, leaving DOGGR in violation of the MOA.

The only way in which the public, and the federal EPA, can be satisfied that DOGGR will meet its obligations for public notice and hearing is to enshrine such procedures in the regulations.

B. Lack of Public Notice When Injection Fluid Source Is Changed Violates the MOA

If an operator changes the source of fluid injectate, the only obligation on the operator is to conduct a chemical analysis of the fluid being injected, to test for metal, polynuclear aromatic hydrocarbons and radionuclides.[41] There is no provision for public notice and opportunity to comment on a change in the source of fluid injectate. Yet clause II(F) of the MOA with EPA requires that public notice and opportunity for comment be provided "[i]f there are substantial changes to [an] approved project." The MOA expressly provides "significant changes in injection fluid" as an example of "substantial changes."[42] A change in source of injection fluid, or the introduction of an additional source of fluid, would clearly result in a significant change in injection fluid. In order to remain in compliance with the MOA with EPA, therefore, the Draft Regulations must provide for public notice and opportunity for comment on any changes in the source of injection fluid.

C. Mechanical Integrity Testing Schedule Violates the MOA

Cl. 1(D)(2) of the MOA requires that "each year, 100% of the disposal wells will be inspected for mechanical integrity." Draft Regulation § 1724.10(j)(2) provides that, after an

[40] *See* Horsley Witten Report, pp. 58 ("Most District 1 UIC staff have never gone through the hearing process", 91 ("No public hearing has ever been conducted in this District [2]"), 123 ("We [District 3] have never had a need to hold a public hearing as part of the approval process"), 162 ("The last public hearing in this district [4] was on December 4, 1986"), 194 ("No public hearings have been conducted [District 5"), 227 ("[District 6] *Have any hearings been held in the past ten years?* None").
[41] Draft Regulations § 1724.7.2.
[42] MOA, Clause F(1).

initial test within three months of injection commencing, "water-disposal wells shall be tested at least once each year, or on a testing schedule approved by the Division…." Thus, DOGGR staff would have the power to set a testing schedule that leaves DOGGR in violation of the MOA, which would justify revocation of primacy.

In order to avoid risking violation of the MOA, Draft Regulation § 1724.10(j)(2) should be amended to prohibit DOGGR staff from setting a testing schedule that requires testing less frequently than once per year.

D. Draft Regulates Violate Requirements for Testing Water Disposal Wells

Draft Regulation § 1724.10(j)(2) provides that, after an initial test within three months of injection commencing, "water-disposal wells shall be tested at least once each year, or on a testing schedule approved by the Division…" This gives DOGGR personnel the power to approve a testing schedule with more than one year between tests. The 1425 Demonstration states that DOGGR will require an operator to "[c]onfirm that the injection fluid is confined to the intended zone of injection by running fluid injection profile surveys… at least once each year [after the first test.]"[43] Therefore, the Draft Regulations potentially put DOGGR out of compliance with the 1425 Demonstration's commitment regarding annual testing.

E. Information Operators Are Required to Provide Is Insufficient for the Purpose of the 1425 Demonstration

Section 3.3(J) of the 1425 Demonstration describes the information that an operator must provide before an injection project is approved. The engineering study must include "casing diagrams indicating the location of cement plugs, and the actual or calculated cement fill behind the casings of all idle, abandoned, or deeper-zone producing wells within the *area affected by the project*, and evidence that abandoned wells *in the area* will not have an adverse effect on the project or cause damage to life, health, property, and natural resources." The Draft Regulations require only that operators provide diagrams of all wells "that are within the *area of review* and that are in the same or a deeper zone as the injection project…"[44] Because the Draft Regulations define the area of review by a standard radius that bears no relation to the area that may be affected by an injection project, operators may well fail to provide the information required by

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[43] 1425 Demonstration, sections B and C.
[44] Draft Regulations. § 1724.7(a)(1)(E).

the 1425 Demonstration to be provided. That is, the Draft Regulations propose to lessen the disclosure obligations on operators. To the extent that they will allow operators to avoid providing information about wells in the area affected by a proposed underground injection project, the Draft Regulations are in violation of the 1425 Demonstration.

VII. SUBSTANTIVE INADEQUACIES WITH THE DRAFT REGULATIONS

A. The Absence of Regulations Addressing Induced Seismicity Is Unacceptable

The Draft Regulations inexplicably fail to address the risks of induced seismicity from wastewater injection and enhanced oil ("EOR") recovery, despite the fact that wastewater injection has been linked to magnitude 4+ earthquakes in California and has led to a surge in induced earthquakes, including damaging earthquakes, in many parts of the country.[45] The failure of the Draft Regulations to require comprehensive detection, monitoring, and mitigation of injection- induced seismicity is a serious deficiency.

Scientists have long-documented that wastewater disposal and EOR can induce earthquakes.[46] In the past decade, induced earthquakes have proliferated and become a major safety concern in many states where wastewater injection has increased.[47] In Oklahoma, for example, a magnitude 5.7 induced earthquake near Oklahoma City in 2011[48] injured two people, destroyed 14 homes, and caused millions of dollars' worth of damage to buildings and infrastructure. A magnitude 5.3 induced earthquake in Trinidad, Colorado, in 2011[49] and

[45] Ellsworth, W.L., Injection-induced earthquakes, Science 341: 6142 (2013) ("Ellsworth 2013"); Rubinstein, J.L. and A.B. Mahani, Myths and facts on wastewater injection, hydraulic fracturing, enhanced oil recovery, and induced seismicity. Seismological Research Letters 86: (July/August 2015) ("Rubinstein 2015").

[46] Nicholson, C. and R. Wesson, Triggered earthquakes and deep well activities Pure Appl. Geophys 139: 561–578 (1992); National Research Council, Induced Seismicity Potential in Energy Technologies National Academies Press (2012); Ellsworth 2013.

[47] Ellsworth 2013; Petersen, M.D. et al., Incorporating induced seismicity in the 2014 United States National Seismic Hazard Model — Results of 2014 workshop and sensitivity studies, U.S. Geological Survey Open-File Report 201 5–1070, (2015)

[48] Keranen, K.M. et al., Potentially induced earthquakes in Oklahoma, USA: Links between wastewater injection and the 2011 M_w 5.7 earthquake sequence, Geology 41: 699-702 (2013); Keranen, K.M. et al., Sharp increase in Central Oklahoma seismicity since 2008 induced by massive wastewater injection, Science 345: 448-451 (2014).

[49] Rubinstein, J. et al., The 2001-present induced earthquake sequence in the Raton Basin of northern New Mexico and southern Colorado, Bulletin of the Seismological Society of America 104 (2014).

magnitude 4.8 induced earthquake in Timpson, Texas, in 2012[50] also caused significant structural damage. EOR has been linked to magnitude 4.6 earthquake near Snyder, Texas.[51]

Earthquakes induced by oil industry wastewater injection have now been documented in California. Scientific research published in early February linked a surge in wastewater injection in 2005 with an earthquake swarm in the Tejon oil field near Bakersfield, with two earthquakes reaching magnitude 4.7.[52] These earthquakes occurred about five miles from the injection wells linked to the seismic activity. In a related 2015 study, researchers identified at least three other cases in Kern County where wastewater injection likely induced earthquakes, including earthquakes greater than magnitude 4.[53] The researchers cautioned that the damage from induced earthquakes can be disastrous: "considering the numerous active faults in California, the seismogenic consequences of even a few induced cases can be devastating."[54]

In California, wastewater injection volumes more than doubled between 2000 and 2014, according to Department of Conservation data, which increases the risk of induced seismicity. Nearly 38 billion gallons (~905 million barrels) of wastewater were injected into California disposal wells in 2014 alone.[55] The use of water-intensive oil and gas recovery techniques, such as hydraulic fracturing, waterflood, and cyclic steam injection, has led to this significant rise in wastewater production. Many of California's wastewater disposal wells are also injecting at rates associated with an increased risk of induced seismicity (e.g., greater than 100,000 barrels per month),[56] and extremely high injection rates of 600,000 barrels per month are frequently observed.[57]

Millions of Californians in major population centers, such as Los Angeles and Bakersfield, are living where high densities of wastewater injection wells are operating near

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[50] Frohlich, C. et al., The 17 May 2012 *M*4.8 earthquake near Timpson, East Texas: An event possibly triggered by fluid injection. Journal of Geophysical Research 119: 581–593 (2014).

[51] Gan, W. and C. Frohlich, Gas injection may have triggered earthquakes in the Cogdell oil field, Texas PNAS 1-6 (2013).

[52] Goebel, T.H.W et al., Wastewater disposal and earthquake swarm activity at the southern end of the Central Valley, California, Geophys. Res. Lett. 43, doi:10.1002/2015GL066948 (2016) ("Goebel 2016").

[53] Goebel, T.H.W. et al., An objective method for the assessment of fluid injection-induced seismicity and application to tectonically active regions in central California (J. Geophys. Res. Solid Earth 120: 7013–7032 (2015) (Goebel 2015").

[54] Goebel 2016, at 7.

[55] California Department of Conservation, Oil and Gas: Online Data, Division of Oil, Gas, and Geothermal Resources, ftp://ftp.consrv.ca.gov/pub/oil/monthly_production_reports/2014/ (last visited on Mar. 2, 2016)

[56] Goebel 2015, at 7016.

[57] Goebel 2015, at 7022.

active faults. In fact, the majority of California's oil industry wastewater injection wells are very close to active faults.[58] When recently active faults are considered (e.g., faults that have caused earthquakes within the past 200 years), 87 of California's active wastewater disposal wells are injecting within one mile of fault, while 350 are injecting within five miles of a fault. When all known faults are considered, nearly one-third of California active wastewater injection wells are within one mile of a fault (350 wells), while half are within five miles of a fault (808 wells).

Of major concern for public safety, DOGGR has continued to permit injection wells very close to faults. In the past year, DOGGR has issued permits for oil companies to drill 20 new wastewater injection wells within five miles of a fault in Kern, Los Angeles, San Luis Obispo, and Santa Barbara counties. Eight of these wells are within one mile of a fault, including large faults with the potential to cause destructive earthquakes.[59] Scientific research has established that high volumes, pressures, and duration of injection all increase the risks of induced seismicity,[60] yet DOGGR continues to allow the oil industry to inject high volumes, rates, and pressures of wastewater near faults.[61] Shockingly, large volumes of wastewater are still being injected into the three wastewater injection wells in the Tejon oil field linked to the 2005 induced earthquake swarm south of Bakersfield.[62] As researchers warned, "[w]astewater injection within this region [southern Central Valley] should be monitored carefully because of the presence of high-permeability fault structures that connect the injection site with the nearby WWF [White Wolf Fault]."[63] The White Wolf Fault was the source of the destructive M 7.3 earthquake in 1952 which was the second largest earthquake in California in the 20th century.

Despite the documented risks from induced seismicity, the Draft Regulations completely fail to address the seismic hazards from injection operations, including regulations to comprehensively detect, monitor, and mitigate induced earthquakes. For example, the regulations

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[58] Arbalaez et al., On Shaky Ground: Fracking, Acidizing, and Increased Earthquake Risk in California, Earthworks, Center for Biological Diversity, and Clean Water Action (Mar. 2014) ("On Shaky Ground") *available at:* http://www.shakyground.org/wp-content/uploads/2014/02/ShakyGround-FINAL1.pdf

[59] DOGGR issued permits for the drilling of 36 new wastewater injection wells and the reworking of 31 existing wells between February 2015 and February 2016. 8 new and 8 reworked wastewater injection wells were within 1 mile of faults including the San Gabriel, Santa Susanna, Oak Ridge, and Mount Poso faults. An additional 12 new and 19 reworked faults were within 5 miles of faults including the Los Alamos, Pleito, and Poso Creek faults.

[60] Rubinstein 2015. *See also* On Shaky Ground.

[61] Goebel 2015.

[62] Goebel 2016 linked three wastewater injection wells to an earthquake swarm in 2005 in the Tejon oil field in southern Kern County: API # 03026630, 03023900, and 03011854. DOGGR injection records indicate that these wells are still receiving massive amounts of wastewater injection at high monthly rates.

[63] Goebel 2016, at 7.

fail to prohibit injection wells near faults. The regulations do not require the oil and gas industry to report, and make publicly available, the fluid injection data needed for researchers to adequately detect and monitor induced seismicity near injection wells, such as hourly injection rates, wellhead pressure, and down-hole pressures, and depth of the injection interval, despite calls from seismologists for this crucial data.[64] The regulations similarly do not require adequate seismic monitoring in California oil fields needed to precisely locate earthquakes, including earthquakes of low magnitudes (e.g., 1.5 and 2) that provide important early warnings that large and potentially dangerous faults are being reactivated by fluid injection before larger earthquakes occur.[65] Moreover, the Draft Regulations fail to require even the most basic best practices recommended by the Environmental Protection Agency for monitoring and mitigating induced seismicity hazards.[66] The failure to address the risks from induced seismicity poses a danger to public safety and must be corrected.

B. Allowing Operators to Avoid Step Rate Tests for Each Injection Well Is Unsound

Section 1724.7(a)(4) of the Draft Regulations exempts operators from conducting a step rate test for each injection well, which is completely inadequate for testing for zonal isolation of injection fluids in the project area. Under the regulations, the operator could estimate a "baseline fracture gradient" for the entire project area based on step rate tests from "select wells within the underground project area." An underground injection project area could encompass numerous wells over a large area. Because the fracture gradient will vary over space, there could be significant differences in the fracture gradient over a large project area which may not be captured by sampling only a subset of wells. The regulations do not specify how the sampling of "select wells" in the project area would be done in a statistically robust way (considering the number of wells selected, their distribution, and their particular characteristics), in order to produce a reliable and sufficiently precautionary estimate of the "baseline fracture gradient" for the entire project area. In short, the proposal to interpolate the fracture gradient for an entire project area based on tests from "select wells" is risky and scientifically unsound.

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[64] McGarr, A. et al., Coping with earthquakes induced by fluid injection Science 47: 830-831 (2015); Rubinstein 2015.
[65] *See supra* note 64.
[66] U.S. EPA, Minimizing and Managing Potential Impacts of Injection-Induced Seismicity From Class II Disposal Wells: Practical Approaches; Underground Injection Control National Technical Workgroup (2014), *available at:*. http://www.epa.gov/sites/production/files/2015-08/documents/induced-seismicity-201502.pdf.

C. Injection Fluid Testing Processes Are Dangerously Inadequate

1. Required Chemical Analyses Too Narrow to Protect Groundwater

Section 1724.7.2 of the Draft Regulations requires analysis of injection fluid for certain specified substances. The substances for which operators must test are limited to the metals, polynuclear aromatic hydrocarbons and radionuclides that are associated with produced oil. Operators are not required to analyze injection fluid for injectate additives that are associated with well stimulation and enhanced oil recovery processes, many of which are known toxics and carcinogens. Nor are operators required to test for substances used in routine well cleanouts or other down-hole activities. The substances for which operators must test are a narrower subset of the range of substances for which operators required to test for when conducting well stimulation.[67]

Disposal wells may receive wastewater that contains fracking fluids, or chemicals used to perform well maintenance. Oil and gas wastewater and fluids injected for enhanced oil recovery may contain additional chemicals added in other phases of production or maintenance of a well. USGS notes that "the chemical additives used in well stimulation activities can include the same/same type of additives used in water- and steam-flooding enhanced recovery operations."[68] There are many chemicals commonly present in produced water, flowback fluid, and fluids injected for enhanced recovery, which are known to be harmful to the health of humans, for which the Draft Regulations do not require operators to test.

Furthermore, under the Draft Regulations, the injection fluid does not need to be analyzed for benzene, a known carcinogen. Benzene, an extremely toxic carcinogen, is a common constituent of oil and gas wastewater in California.[69] A survey of chemical analyses reported by well stimulation companies posted to the DOGGR reporting website shows that benzene is detected in flowback fluid at high levels—on average, 700 times the federal drinking

[67] 14 C.C.R. §1783.4(f) (groundwater monitoring); § 1788 (base fluid and waste water).

[68] Taylor, Kim et al Oil, *Gas and Groundwater Quality in California - a discussion of issues relevant to monitoring the effects of well stimulation at regional scales*, California Water Science Center (Dec. 2014), p. 8.

[69] California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, *Benzene in Water Produced from Kern County Oil Fields Containing Fresh Water* (1993) ("DOGGR Benzene in Water Report").

water limit.[70] DOGGR's own study has found benzene in produced water samples at concentrations at 3,600 times the U.S. EPA's limit for drinking water.[71]

In its recently-published report on hydraulic fracturing in California ("CCST Report"), the California Council of Science and Technology identified over 300 unique chemicals being used in hydraulic fracturing fluids in California.[72] Nearly one third of those chemicals did not have a Chemical Abstracts Service Registry Number (CASRN). Chemical additives without a CASRN cannot be fully evaluated for hazard, risk, and environmental impacts due to lack of specific identification.[73] The absence of any such evaluation means that it cannot be concluded that such chemicals will not cause harm. In the absence of a positive conclusion that a chemical will not cause harm, it must be concluded that they "may" cause harm. Accordingly, USDWs must be protected from contamination by chemicals without a CASRN. Of the chemicals used in hydraulic fracturing processes in California, "approximately one-half of chemicals used do not have publicly available results from standard aquatic toxicity tests. More than one-half are missing biodegradability, water-octanol partitioning analysis, or other characteristic measurements that are needed for understanding hazards and risks associated with chemicals."[74]

Regulators must be aware of the full spectrum of substances being injected in order to regulate effectively. Accordingly, the range of substances to be tested for must be expanded, so that DOGGR, and operators, aware of all fluids and chemicals injected or emplaced into a Class II injection well. They should be expanded to at least encompass the range of substances that operators must test for after conducting well stimulation. Without such chemical information, it is impossible to detect contamination or predict how chemicals will interact or migrate in the subsurface. Fluids from a source using chemicals without a CASRN must not be accepted for disposal.

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[70] Cart, J., *High Levels of Benzene Found in Fracking Wastewater*, Los Angeles Times (Feb. 11, 2015), *available at:* http://www.latimes.com/local/california/la-me-fracking-20150211-story.html#page=1; California Department of Conservation, Division of Oil, Gas and Geothermal Resource, Well Stimulation Database http://maps.conservation.ca.gov/doggr/iwst_index.html (last visited on Mar. 2, 2016); 40 C.F.R. § 141.61(a) (maximum contaminant level for benzene is 0.005 mg/L, or 5 ppb).

[71] DOGGR Benzene in Water Report at p. 11, Table 1 (finding produced water sample with 18.0 parts per million, 3,600 times greater than the EPA limit for drinking water (0.005 parts per million).

[72] California Council of Science and Technology, An Independent Scientific Assessment of Well Stimulation in California, Volume II: Potential Environmental Impacts of Hydraulic Fracturing and Acid Stimulations (Jul. 2015), p. 50.

[73] *Id.*

[74] *Id.*

2. Obligation to Provide Analysis Is Not Absolute

Even this insufficient analysis can be avoided if it is "infeasible" for an operator to provide it.[75] The Draft Regulations fail to indicate whether a determination about "infeasbility" is made by the operator, or by DOGGR, nor do they provide any standards or guidance about what might make providing the information "infeasible." It is entirely inappropriate for operators to be able to avoid providing information simply on the assertion that it is infeasible to do so. It is likewise inappropriate for DOGGR staff to be able to exempt an operator from providing information, particularly in the absence of any regulatory guidance about what constitutes "infeasibility." This exception should be removed from the Draft Regulations.

3. Testing Frequency Is Insufficient

Section 1724.10(d) of the Draft Regulations requires that chemical analyses be provided only every two years, when the source of an injection fluid is changed, when an additional source is introduced, or upon the request of the Supervisor. This is woefully inadequate. It is entirely possible that the chemical profile of an injectate may change dramatically, without the source of the injection fluid changing. For instance, a Class II disposal well may be injecting wastewater from a particular field that is being hydraulically stimulated. If the operator of the stimulated wells changes the composition of the fluid being injected, then the chemical profile of the wastewater may also change accordingly, even though the source of the fluid remains constant. In order to ensure that DOGGR is aware of all substances being injected into a Class II well, the regulations should require testing every 30 days, when the source of an injection fluid is changed, when an additional source is introduced, upon the request of the Supervisor, or when a reasonable operator would have reason to believe that the chemical profile of the fluid being injected may have changed.

4. Test Results and Sources of Injected Fluid Must Be Publicly Disclosed

The Draft Regulations do not require any public disclosure of the results of injection fluid testing. While disclosure, by itself, does not make Class II injections safer, or reduce their environmental impacts, it is one important component of the full set of necessary safeguards. Disclosure rules provide nearby residents with information about the chemicals being used,

[75] Draft Regulations, § 1724.7(d).

transported, and released in their communities, and provides first responders with information necessary for appropriately responding to accidents and emergencies. Medical professionals also require information about the chemicals their patients may have been exposed to, and the concentrations, for diagnosis and treatment. If an operator conducts well stimulation, they must disclose all the chemicals injected into the well, the volume of fluids injected, and the source of base fluid.[76] The same obligations should be imposed on operators injecting fluid underground in other circumstances.

D. Groundwater Monitoring Obligations Must Be Included

The Draft Regulations do not make any provision for groundwater monitoring. Monitoring of groundwater in nearby aquifers should be required in order to verify that isolation is achieved. The groundwater monitoring criteria developed for well stimulation projects should be examined for applicability to injection projects.[77] Many of the model criteria for groundwater monitoring near well stimulation projects is applicable to injection projects. United States Geologic Survey (USGS), in a paper commissioned by the State Water Resources Control Board, asserts that the impacts of well stimulation on groundwater may be indistinguishable from enhanced recovery (i.e. Class II wells), as the same contamination pathways, and similar chemicals may be present.[78] Monitoring groundwater for impacts from underground injection wells would be consistent with the State's current program of monitoring groundwater for impacts from well stimulation. One transferable aspect of the well stimulation monitoring program is the regional groundwater monitoring programs being developed for oil fields where stimulation occurs. These plans should also be developed for any fields where underground injection occurs. Well by well monitoring should also be considered, especially in cases where injection wells penetrate, or are adjacent to, aquifers with beneficial uses.

E. Project Approval Process Lacks Clarity, Transparency and Important Data Requirements

1. Lack of Clarity of Scope of a "Project"

[76] 14 C.C.R. § 1788.
[77] *See* Pub. Resources Code § 3160(b) and 14 C.C.R. §§ 1783 – 1784.
[78] *See supra* note 68, p.8.

The Draft Regulations require a Project Approval Letter for an "underground injection project."[79] An "underground injection project" is a "sustained or continual injection into one or more wells over an extended period in order to add fluid to a zone for the purpose of enhanced oil recovery, disposal, or storage."[80] It is unclear how many wells might be included in a single "project." It is also unclear how many wells, or over what period of time, a Project Approval Letter might cover. The Draft Regulations should be clear about when a project ceases, and the circumstances in which more than one well might be included in a single letter.

While the Draft Regulations are to be commended for requiring DOGGR to "periodically review the terms and conditions of the Project Approval Letter to ensure that they effectively prevent damage to life, health, property and natural resources,"[81] the failure to specify the frequency with which reviews must occur renders the provision hollow. DOGGR has, for a range of reasons, historically failed at its regulatory duties. The process of updating the underground injection regulations stems from DOGGR's failure to comply with its own UIC program - it issued thousands of Class II well permits unlawfully.[82] It acknowledged in 2012 that it had been aware since 2009 that the UIC Program had failed to comply with state law and regulations,[83] yet it took no action until the federal EPA and public outcry demanded. The public in California cannot have any confidence that DOGGR will carry out reviews of Project Approval Letters in the absence of a schedule required by regulation.

2. Period of Validity of Project Approval Letter Unclear

As set out above, an "underground injection project" is defined as "continuous" injection of fluid. However, section 1734.10(l)(6) of the Draft Regulations prohibits an operator from resuming injection into a well without subsequent approval from DOGGR if "[t]he well has been inactive for more than two years." An injection project cannot be "continuous" if there may be a break in injection of up to two years. The lack of clarity surrounding what constitutes a "project," and when a new Project Approval Letter must be obtained, must be addressed.

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[79] Draft Regulations, § 1724.6.
[80] Draft Regulations, § 1720(e).
[81] Draft Regulations, § 1724.6(c).
[82] Bohlen, Steve, State Oil and Gas Supervisor, DOGGR, and Jonathan Bishop, Chief Deputy Director, State Water Resources Control Board, Letter to Michael Montgomery, U.S. EPA (Jul. 31, 2015).
[83] California Department of Conservation, Division of Oil, Gas and Geothermal Resources, Response to the US EPA June 2011 Review of California's UIC Program (Nov. 2012) ("November 2012 letter"), p. 1.

3. Notification to Neighbors Is Unclear and Insufficient

Section 1724.7(a)(3)(H)(5) requires a request for a Project Approval Letter to be accompanied by "copies of letters of notification sent to offset operators adjacent to the proposed project area and within the area of review." This is the only reference to notification of neighbors of a proposed underground injection project. Most importantly, the Draft Regulations do not actually require an operator to send notifications. Furthermore, it is totally unclear who might constitute an "operator adjacent to the proposed project area." At the very least, the term appears to exclude neighboring property owners and tenants who do not operate some kind of Class II or oil or gas well. There is no discernible reason for excluding property neighbors or those using water wells in the vicinity of an underground injection project. It also appears to exclude any persons who have an interest in land that does not share a boundary with the underground injection project. This is an arbitrary and inappropriate mechanism for determining the geographic scope of notifications. The Draft Regulations must be amended to make clear that the operator of a proposed underground injection project must give notice to all operators, property owners and tenants who are adjacent to the proposed project area or who are within the area of review of a proposed underground injection project.

4. Numerical Groundwater Modeling Should Be Included in the Project Data Requirements

The project data requirements[84] do not require operators of a proposed underground injection project to provide any kind of analysis of the projected flow of groundwater under the pumping and injecting conditions that the proposed project is will impose. Numerical (computer-based) models of groundwater systems are commonly used to simulate the flow of groundwater, including the response of water levels across aquifer boundaries under conditions of injection and pumping.[85] Operators should be required to provide a numerical groundwater model as part of the project data requirements.

F. Lack of Clarity and Transparency Regarding Performance Data

Section 1724.10(h) of the Draft Regulations provides that "[d]ata shall be maintained to show performance of the project and to establish that no damage to life, health, property, or natural resources is occurring by reason of the project. Project data shall be available for periodic

[84] Draft Regulations, § 1724.7.
[85] Hagemann, Matt, PG, C. Hg., Comments on the Arroyo Grande Aquifer Exemption Application (Dec. 14, 2015), p. 5.

inspection by Division personnel." DOGGR should not rely upon operators to maintain this information. DOGGR cannot make an informed decision about the safety on an operation unless it has such information in front of it. If information were to be held by an operator, DOGGR would likely only ever request it when an incident prompts DOGGR to request it. That is, the information would only be provided *after* damage to life, health, safety, property or natural resources occurs, rendering the purpose of collecting such data pointless. A regulatory agency without knowledge of the risks involved does not constitute "oversight" in any meaningful way. In addition to collecting the data, DOGGR should disclose it to the public. There is no good reason why the public should be denied access to information that would demonstrate the safety (or safety deficiencies) of underground injection projects.

G. Defined Terms Not Used in the Draft Regulations

Section 1720.1(c) defines "surface expression containment measure" as "an engineered measure undertaken in accordance with all state and local requirements to contain or collect the fluids from a surface expression, including but not limited to subsurface collection systems, collection wells, cisterns, culverts, French drains, collection boxes, or gas hoods or other gas collection system." However, the term is not used anywhere in the draft regulations, nor elsewhere in the Public Resources Code. The term "surface expression" is itself defined in section 1720.1(b), while not being used anywhere other than in the definition of "surface expression containment measure." The definition of terms not used in the Draft Regulations demonstrates a concerning lack of attention to the Draft Regulations. It emphasizes the importance and necessity of completing a single, comprehensive package of regulatory reform for underground injection projects of all kinds, rather than approaching this important task in a piecemeal fashion.

VIII. DRAFT REGULATIONS REQUIRE A PROGRAM REVISION

Clause II(G) of the MOA specifies that a program revision may be necessary "when the Division's or EPA's statutory authority is modified or when there is substantial modification to the program." If the Draft Regulations were to be implemented, they would clearly amount to a substantial modification of California's UIC Program. They would, for instance, purport to authorize injection above fracture gradient, and seek to allow Project Approval Letters to be assessed by reference to an AOR that, for cyclic steam wells, is far smaller than DOGGR's policy has provided for or the federal regulations prescribe. Accordingly, DOGGR must follow the procedure for program revision set out in 40 C.F.R. § 145.32.[86] However, as described above, the Draft Regulations are a violation of the federal law, the MOA and the 1425 Demonstration. Therefore, although DOGGR must follow this process, the federal EPA cannot approve the Draft Regulations as they stand.

Accordingly, we recommend DOGGR work towards regulations that are consistent with the law and its obligations under the MOA and 1425 Demonstration, and that adequately protect the public and the environment from the risks of unconventional drilling techniques and wastewater disposal injections. When the Draft Regulations actually comply with state and federal law, DOGGR should submit a modified program description, Attorney General's statement and Memorandum of Agreement to EPA for approval.

IX. EPA MUST BE NOTIFIED OF DRAFT REGULATIONS

Clause II(A) of the MOA between DOGGR and the EPA requires DOGGGR to promptly inform EPA of "any proposed or pending modifications to laws, regulations, or guidelines… that might affect the program." Accordingly, DOGGR must ensure that it has notified the EPA of the issuance of these Draft Regulations.

X. EPA MUST BE NOTIFIED OF CHANGES TO MECHANICAL INTEGRITY TEST

The 1425 Demonstration describes the state's UIC program as requiring that all wells have "mechanical integrity demonstrated by performing fluid injection surveys to demonstrate that the injected fluids are confined to the zones of intended injection."[87] The MOA requires that, if DOGGR "proposes to allow any mechanical integrity tests other than those specified or justified in the 1425 Demonstration," DOGGR must provide EPA "sufficient information about the proposed test that a judgment about its usefulness and reliability can be made."[88]

Section 1724.7.2(j) of the Draft Regulations proposes a mechanical integrity (MIT) test comprising of a two-part demonstration, with pressure testing of the casing-tubing annulus to determine the absence of leaks, and a second part consisting of a test to demonstrate that there is

[86] The MOA states that the procedure to be followed is that set out in 40 C.F.R. § 123.13(b). That provision was modified (see 48 Fed. Reg. 14,146) and is now 40 Fed. Reg. § 145, Subpart D.
[87] 1425 Demonstration, § 3.3(H).
[88] MOA, Cl. 1(E)(1).

no fluid migration behind the casing, tubing, or packer. Because the two-part proposed testing process will involve tests other than those specified in the 1425 Demonstration, DOGGR must notify EPA about this change.

XI. CONCLUSION

These Draft Regulations reveal an agency that has yet to properly take responsibility for the role that its failure to adequately regulate underground injection projects has played in the oil and gas disasters that have occurred throughout California. It is the protection of USDWs that must be of paramount concern to DOGGR. It is this goal that should form the guiding principle for any amendment of the UIC Regulations, not the convenience and desires of oil and gas producers. It is within DOGGR's power to enact such regulations. If it is serious about protecting Californian communities and California's precious groundwater from the risks posed by Class II disposal and enhanced oil recovery wells, DOGGR must proceed to do so.

Should you have any further questions, please feel free to contact me.

Yours sincerely,

Clare Lakewood
Staff Attorney, Climate Law Institute
Center for Biological Diversity

Enclosures

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APPENDIX A

Document 1:

Memorandum of Agreement dated September 29, 1982, as originally posted to Department of Conservation FTP Site

Underground Injection Control Program
Memorandum of Agreement
Between
California Division of Oil and Gas
and
the United States Environmental Protection Agency
Region 9

I. General

This Memorandum of Agreement ("Agreement") establishes the responsibilities of and the procedures to be used by the Division of Oil and Gas ("Division") and the United States Environmental Protection Agency ("EPA") in administration of wells in the Class II portion ("Class II program") of the Underground Injection Control ("UIC") program in California. In general, this Agreement supplements the program described in the demonstration submitted in accordance with Section 1425(a) of the Safe Drinking Water Act ("1425 demonstration").

After it is signed by the Supervisor and the Regional Administrator, this Agreement shall become effective on the date notice of the Class II program approval is published in the Federal Register. The parties will review this Agreement at least once each year during preparation of the annual program update, during the State-EPA agreement ("SEA") process or at other times as appropriate (e.g. at mid-year review). The annual SEA shall be consistent with this Agreement and may not override this Agreement.

This Agreement may be modified upon the initiative of either party in order to ensure consistency with State or Federal statutory or regulatory modifications or supplements, or for any other purpose mutually agreed upon. Any such modifications or supplements must be in writing and must be signed by the Supervisor and Regional Administrator.

This Agreement shall remain in effect unless EPA determines that the Division's 1425 demonstration is no longer valid. Such a determination by EPA will be in accordance with Section 1425(c) of the Safe Drinking Water Act ("SDWA").

Nothing in this Agreement shall be construed to alter any requirements of SDWA or to restrict EPA's authority to fulfill its oversight and enforcement responsibilities under SDWA or other Federal laws, or to restrict the Division's authority to fulfill its responsibilities under State statutes. Nothing in this Agreement shall require or be construed to require EPA to violate Federal law or the Division to violate State law.

II.

A. Policy Statement

The purpose of the UIC program is to prevent any underground injection that endangers an underground source of drinking water ("USDW").

The Division has primary responsibility and authority over all Class II injection wells in the State of California. This includes Class II wells drilled and operated on Federally owned lands, but does not include such wells on Indian lands. The Division is responsible for administering the Class II program including but not limited to reports, permits, monitoring and enforcement actions. Implementation of the Class II program will be as described in the 1425 demonstration and will be supported by an appropriate level of staff and resources.

The Supervisor and the Regional Administrator agree to maintain a high level of cooperation and coordination between Division and EPA staff to assure successful and effective administration of the Class II program.

The Division shall promptly inform EPA of any proposed or pending modifications to laws, regulations, or guidelines, and any judicial decisions or administrative actions that might affect the program and the Division's authority to administer the program. The Division shall promptly inform EPA of any resource allocation changes (e.g. personnel, budget, equipment) that might affect its ability to administer the program.

EPA shall promptly notify the Division of the issuance, content, and meaning of Federal statutes, regulations, guidelines, standards, judicial decisions, policy decisions, directives, and other factors (including budgetary changes) that might affect the Class II program.

B. Information Sharing

1. Division

The Division agrees that all information and records obtained or used in the administration of the Class II program including all UIC permit files shall be available for inspection by EPA or its authorized representative upon request. Division records may be copied by the EPA only when they are required by EPA to bring an enforcement action or for other such specific purpose. Any information obtained from the Division by EPA that is subject to a claim of confidentiality shall be treated by EPA in accordance with EPA regulations governing confidentiality (40 CFR Part 2 and 40 CFR 122.19).

The Division shall retain records used in the administration of the program for at least three years (40 CFR 30 and 40 CFR 35). If an enforcement action is pending, then all records pertaining to such action shall be retained until such action is resolved or the previously mentioned time period is met.

2. EPA

Copies of any written comments about the Division's program administration received by EPA from regulated persons, the public, and Federal, State, and local agencies will be provided to the Supervisor within thirty (30) days of receipt.

3. Emergency Situations

Upon receipt of any information that any Class II injection operation is endangering human health or the environment and requires emergency response, the party in receipt of such information shall immediately notify by telephone the other party of the existence of such a situation.

C. Permits

1. Division

Within 10 working days of receipt, the Division shall provide a written response to any written notice of intent to commence drilling.

2. EPA

Upon receipt by EPA, any Class II permit application and supporting information shall be immediately forwarded to the Division.

Some facilities and activities may require permits from the Division and EPA (and/or other State agencies) under different programs. When appropriate, the Division and EPA will participate in a joint permit processing procedure. The procedure will be developed on a case by case basis.

D. Compliance, Monitoring and Enforcement

1. Division

The Division shall adhere to the compliance monitoring, tracking, and evaluation program described in the 1425 Demonstration. The Division shall maintain a timely and effective compliance monitoring system including timely and appropriate actions on non-compliance.

Each year, 100% of the disposal wells will be inspected for mechanical integrity.

2. EPA

EPA shall conduct periodic site and activity inspections on injection operations, giving priority to operations having the greatest potential to endanger public health.

EPA may participate with the Division in the inspection of wells or operator records. EPA shall notify the Division usually at least ten (10) days prior to any proposed inspection and shall describe the well(s) or record (s) to be inspected and the purpose of such inspection. If the Division fails to take adequate enforcement action against a person violating the requirements for a Class II well, EPA may take Federal enforcement action. Federal enforcement actions will be in accordance with the State, facility and public notification procedures in Section 1423 of SDWA.

3. Emergency Situations

Situations endangering human health will receive immediate and paramount attention by the Division and EPA. The party with initial knowledge of such situation shall immediately notify the other party by telephone.

E. Program Review and Evaluation

1. Division

The Division shall provide EPA with an annual report on the recent operation of the Class II program. Specific contents of the report are described in Attachment #1 and may be renegotiated from time to time. The period to be covered by the annual report shall be the calendar year ending December 31, with reports completed and available to EPA no more than 60 days later (March 1).

In addition, the Division shall provide a separate report of preventive actions taken by operators of new Class II wells. At minimum, this report shall include:

a. the number and general type (e.g. injection pressure limit) of preventive actions proposed in the applications;

b. the number and general type of preventive actions actually taken; and

c. if necessary, a brief summary explaining the reason(s) for any differences between proposed and actual preventive actions (e.g., pending actions).

The report is due within 3 months after the second anniversary of the effective date of this Agreement. The final format will be negotiated at least 3 months prior to the due date.

If the Division proposes to allow any mechanical integrity tests other than those specified or justified in the 1425 Demonstration, the Division shall provide in advance to EPA sufficient information about the proposed test that a judgment about its usefulness and reliability can be made.

2. EPA

EPA shall conduct mid-year evaluations at least during the first 2 years of the Division's operation of the program. In part, the mid-year evaluations will be based on the reports provided above. At least 10 days prior to the evaluation, EPA shall notify the Division regarding the information, material, and program areas that will be covered. This may include selected permit files, budget records and public notification and complaint files. The evaluation may be conducted at either the Division's headquarters or one of its district offices.

F. Public Participation

1. Division

The Division shall provide adequate public notice for its proposed actions as described in the Division's 1425 Demonstration. At minimum, the Division shall provide a 15 day public comment period, and make the non-confidential portions of the project plan and the representative Report on Proposed Operations available for review. If the Supervisor determines that a public hearing is necessary, public notice shall be provided at least 30-days prior to the public hearing.

If there are any substantial changes to the approved project plan or representative Report on Proposed Operations, additional public notice will be provided. Examples of substantial changes include significant increases in injection pressures, changes in injection zone, or significant changes in injection fluid.

Copies of such notices shall also be sent to:

a. Director, Water Management Division, EPA-Region 9;

b. Chairperson, State Water Resources Control Board; and

c. Chairperson of the affected Regional Water Quality Control Board.

The Division's final decision on proposed actions shall contain a response to comments that summarizes the substantive comments received and the disposition of the comments. This shall become a part of that particular project file.

At a minimum, the Division shall apply these public participation procedures to applications for new underground injection projects, significant modifications to existing permits, and to aquifer exemptions.

2. EPA

EPA shall participate at any scheduled public hearing at the request of the Division. Such requests shall be made at least 10 days prior to the hearing.

Any appropriate comments on the proposed action shall be made by EPA within the normal fifteen day comment period. The exception is the designation of exempted aquifers (see the section on Aquifer Exemptions).

G. Program Revision

A program revision may be necessary when the Division's or EPA's statutory authority is modified or when there is a substantial modification to the program. The procedure for revising the program shall be that described in 40 CFR 123.13(b).

H. Aquifer Exemption

An Underground Source of Drinking Water (USDW) may be exempted for the purposes of a Class II injection well if it meets the criteria in 40 CFR 146.04.

Aquifers exempted by the Division and EPA under this Agreement shall only be applicable for the injection of fluids related to Class II activities defined in 40 CFR 146.05(b).

Aquifer exemptions made subsequent to the effective date of this Agreement shall not be effective until approved by the Administrator or Regional Administrator (if delegated) in writing.

After the effective date of this Agreement, an aquifer exemption must be in effect prior to or concurrent with the issuance of a Class II permit for injection wells into that aquifer.

Aquifers which were proposed for exemption in the 1425 Demonstration and exempted are identified in Attachment #2. Aquifers proposed for exemption in the 1425 Demonstration and not exempted will be phased out within 18 months of the effective date of this Agreement (Attachment #3). Any aquifer or portion of an aquifer denied an exemption may be resubmitted for consideration. At minimum, the resubmission should include either new data, new boundaries or other modification to the original proposal.

All exempted aquifers are subject to review by the Division and by EPA. For good reason and by mutual agreement between the Division and EPA, the exemption status of an aquifer can be withdrawn. The public participation procedures in the 1425 Demonstration shall be applied prior to the withdrawal of any exemption status.

1. EPA

Within 10 days after receipt of the information on the aquifer(s) proposed by the Division for exemption, EPA shall notify the Division if any additional information is deemed appropriate. EPA shall either approve or disapprove the aquifer exemption within 60 days after receipt of all appropriate information. Any disapproval by EPA shall state the reasons for the decision. Requests for additional information and final determinations on aquifer exemptions shall be in written form.

If the new aquifer proposed for exemption is a non-hydrocarbon bearing USDW, EPA will coordinate its public participation activities on aquifer exemptions with the Division's public participation activities during project review.

I. Other Agency Involvement

The Division shall administer the Class II program and maintain close cooperation with California's State Water Resources Control Board (SWRCB) and the Minerals Management Service.

J. Definitions

1. Class II well is defined in 40 CFR 146.05(b).

2. Aquifer is defined in 40 CFR 146.03 and 122.3.

3. Day in this Agreement is defined as a working day.

4. Underground Source of Drinking Water (USDW) is defined in 40 CFR 146.03 and 122.3.

5. 1425 Demonstration includes:

a. the Division's primacy application dated April, 1981;

b. the additional information provided by letter dated March, 1982; and

c. the clarifying information provided by letter dated September, 1982.

Sonia F. Crow	for M.G. Mefferd
Sonia F. Crow	Simon Cordova
Regional Administrator	State Oil and Gas Supervisor
Environmental Protection Agency	California Division of Oil and Gas
Region 9	
Sept. 29, 1982	Sept. 28, 1982
Date	Date

Attachment 1

Annual Report Contents

At a minimum, the Annual Report shall include:

a. an updated inventory;

b. a summary of surveillance programs including results of monitoring and mechanical integrity testing, the number of inspections conducted, the number of new wells, corrective actions ordered and witnessed, instances of wells out of compliance and their current status;

c. an account of all complaints reviewed by the Division and the actions taken;

d. results of the review of existing wells made during the year;

e. a summary and status of the enforcement actions taken;

f. number of emergency permits issued and current status; and

g. instances of variances and discretionary exemptions during the year.

Attachment 2

Exempted 1425 Demonstration Aquifers

All oil and gas producing aquifers identified in Volumes I, II, and III of the California Oil and Gas Fields submitted in the 1425 Demonstration dated April 20, 1981 are exempted.

In addition, the following aquifers are also exempted.

DISTRICT	FIELD	FORMATION/ZONE
2	Ramona	Pico
2	Oat Mountain	Undiff.
2	Simi	Sespe
3	San Ardo	Santa Margarita
3	San Ardo	Monterey "D" Sand
3	San Ardo	Monterey "E" Sand
3	Monroe Swell	Santa Margarita
4	Buena Vista	Tulare
4	Kern Bluff	Vedder
4	Kern River	Vedder*
4	Mountain View	Kern River
4	Pleito	Chanac
4	Pleito	Kern River
4	Poso Creek	Santa Margarita
5	Coalinga	Santa Margarita
5	Coalinga	Etchegoin-Jacalitos
5	Guijarral Hills	Etchegoin-Jacalitos*
5	Helm	Tulare-Kern River
5	Riverdale	Pliocene
5	Turk Anticline	San Joaquin
6	Sutter Buttes Gas	Kione*

* oil and/or gas producing

Attachment 3

1425 Demonstration Aquifers Not Exempted

DISTRICT	FIELD	FORMATION/ZONE
2	South Tapo Canyon	Pico
4	Blackwell's Corner	Tumey
4	Kern Bluff	Kern River
4	Kern Front	Santa Margarita
4	Kern River	Chanac
4	Kern River	Santa Margarita
4	Mount Poso	Walker
4	Round Mountain	Olcese
4	Round Mountain	Walker
6	Bunker Gas	Undiff.
6	Wild Goose	Undiff.

Document 2:

December 13, 1982 Memorandum From Region IX Staff To US EPA Headquarters Enclosing Competing MOA With No Exemptions Denied

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Environmental Protection Agency
Region 1X
215 Fremont St.
San Francisco, CA. 94105

DEC 13 1982

California's Application for Primacy Over Class II Wells in the Underground Injection Control (UIC) Program

William M. Thurston
Chief, Water Supply Section, Region 9

Phil Tate
UIC Review Coordinator
State Program Division (WH-550)

Attached are the State Attorney General's response to the UIC Review Team's comments dated November 5, 1982 and a copy of the Memorandum of Agreement between the Division of Oil and Gas and EPA, Region 9.

With the addition of these attachments, all known issues regarding the primacy application have been resolved. If you have any questions, please don't hesitate to call Nathan Lau at 454-8274 or me at 454-8221.

Attachments

CONCURRENCES

YMBOL		W-3	W-2	PSB				
URNAME	N. Lau	Reames	Thurston	mail out				
ATE	12/13/82	12/13/82	12/13/82	DEC 13 1982				

PA Form 1320-1 (12-70)

OFFICIAL FILE COPY

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Environmental Protection Agency
Region 1X
215 Fremont St.
San Francisco, CA. 94105

DEC 13 1982

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EPA Form 1320-1 (12-70)

OFFICIAL FILE COPY

State of California
Department of Justice
George Deukmejian
(PRONOUNCED DUKE-MAY-GIN)
Attorney General

3580 WILSHIRE BLVD
LOS ANGELES 90010
(213) 736-2125

U.S.E.P.A. REGION 9 COMM CNTR
DEC 6 10 54 AM '82

December 3, 1982

Richard E. Reavis, Chief
California Branch
Region IX
United States Environmental Protection Agency
215 Fremont Street
San Francisco, CA 94105

Re: California Application for Primacy, Class II UIC Program

Dear Mr. Reavis:

The Headquarters Underground Injection Control (UIC) Primacy Review Team reviewed the responses made by the California Division of Oil and Gas (CDOG) to comments made by the Environmental Protection Agency (EPA) on CDOG's primacy application. Except for items 2 and 4, the CDOG's responses were found to be adequate. With respect to items 2 and 4, the Review Team indicated that the responses would be adequate if it could obtain from the California Attorney General's office, the legal representative of the CDOG, assurances on two matters. The first matter on which assurance is sought is that the CDOG can enforce the conditions set out in the letter of approval, which is the first step in the CDOG's two-step permitting process for underground injection. The second matter on which assurance is sought is that compliance by the operator with the letter of approval does not relieve the operator from compliance with all applicable statutes and regulations. We are able to give you the assurances you seek.

Under section 1724.6 of Title 14 of the California Administrative Code, prior approval of any underground injection or disposal project must be obtained from the CDOG before the project can begin. This prior approval is in the form of a letter setting forth the conditions upon which the approval to proceed is given. Failure of an operator to comply with any conditions set forth in the letter of approval would constitute proceeding with the project without the approval of the CDOG. This would be a violation by the operator of section 1724.6 of Title 14 of the California Administrative Code which would enable the CDOG to invoke the enforcement procedures available to it to compel compliance with the terms of the letter of approval.

The letter of approval may set forth special operational requirements that relate specifically to the project being approved. These requirements are in addition to, not in lieu of, the requirements of statutes and regulations applicable to underground injection and disposal projects. All operators must comply with applicable provisions of the statutes and regulations, and the CDOG has no authority to exempt an operator from such compliance. The statutes and regulations (see for example section 1724.10 of Title 14 of the California Administrative Code) provide general requirements for underground injection projects. However, unique characteristics of each project site may necessitate, in addition, site-specific requirements which is the function of the letter of approval to provide.

If this office can be of any further assistance in the process of obtaining EPA approval of the CDOG's primacy application, please do not hesitate to call.

Very truly yours,

Alan V. Hager
Deputy Attorney General

AVH:mjp
cc: M. G. Mefferd

Underground Injection Control Program
Memorandum of Agreement
Between
California Division of Oil and Gas
and
the United States Environmental Protection Agency
Region 9

I. General

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All exempted aquifers are subject to review by the Division and by EPA. For good reason and by mutual agreement between the Division and EPA, the exemption status of an aquifer can be withdrawn. The public participation procedures in the 1425 Demonstration shall be applied prior to the withdrawal of any exemption status.

1. EPA

Within 10 days after receipt of the information on the aquifer(s) proposed by the Division for exemption, EPA shall notify the Division if any additional information is deemed appropriate. EPA shall either approve or disapprove the aquifer exemption within 60 days after receipt of all appropriate information. Any disapproval by EPA shall state the reasons for the decision. Requests for additional information and final determinations on aquifer exemptions shall be in written form.

If the new aquifer proposed for exemption is a non-hydrocarbon bearing USDW, EPA will coordinate its public participation activities on aquifer exemptions with the Division's public participation activities during project review.

I. Other Agency Involvement

The Division shall administer the Class II program and maintain close cooperation with California's State Water Resources Control Board (SWRCB) and the Minerals Management Service.

J. Definitions

1. Class II well is defined in 40 CFR 146.05(b).
2. Aquifer is defined in 40 CFR 146.03 and 122.3.
3. Day in this Agreement is defined as a working day.

4. Underground Source of Drinking Water (USDW) is defined in 40 CFR 146.03 and 122.3.

5. 1425 Demonstration includes:

a. the Division's primacy application dated April, 1981;

b. the additional information provided by letter dated March, 1982; and

c. the clarifying information provided by letter dated September, 1982.

Sonia F. Crow

Sonia F. Crow
Regional Administrator
Environmental Protection Agency
Region 9

Sept. 29, 1982
Date

Simon Cordova for M.G. Mefferd
State Oil and Gas Supervisor
California Division of Oil and Gas

Sept. 28, 1982
Date

Attachment 1

Annual Report Contents

At a minimum, the Annual Report shall include:

a. an updated inventory;

b. a summary of surveillance programs including results of monitoring and mechanical integrity testing, the number of inspections conducted, the number of new wells, corrective actions ordered and witnessed, instances of wells out of compliance and their current status;

c. an account of all complaints reviewed by the Division and the actions taken;

d. results of the review of existing wells made during the year;

e. a summary and status of the enforcement actions taken;

f. number of emergency permits issued and current status; and

g. instances of variances and discretionary exemptions during the year.

Attachment 2

Exempted 1425 Demonstration Aquifers

All oil and gas producing aquifers identified in Volumes I, II, and III of the California Oil and Gas Fields submitted in the 1425 Demonstration dated April 20, 1981 are exempted.

In addition, the following aquifers are also exempted.

DISTRICT	FIELD	FORMATION/ZONE
2	Ramona	Pico
2	Oat Mountain	Undiff.
2	South Tapo Canyon	Pico
2	Simi	Sespe
2	San Ardo	Santa Margarita
3	San Ardo	Monterey "D" Sand
3	San Ardo	Monterey "E" Sand
3	Monroe Swell	Santa Margarita
4	Blackwell's Corner	Tumey
4	Kern Bluff	Kern River
4	Kern Front	Santa Margarita
4	Kern River	Chanac
4	Kern River	Santa Margarita
4	Mount Poso	Walker
4	Round Mountain	Olcese
4	Round Mountain	Walker
4	Buena Vista	Tulare
4	Kern Bluff	Vedder
4	Kern River	Vedder*
4	Mountain View	Kern River
4	Pleito	Chanac
4	Pleito	Kern River
4	Poso Creek	Santa Margarita
5	Coalinga	Santa Margarita
5	Coalinga	Etchegoin-Jacalitos
5	Guijarral Hills	Etchegoin-Jacalitos*
5	Helm	Tulare-Kern River
5	Riverdale	Pliocene
5	Turk Anticline	San Joaquin
6	Sutter Buttes Gas	Koine*
6	Bunker Gas	Undiff.
6	Wild Goose	Undiff.

*Oil and/or gas producing

Document 3: May 17, 1985 letter from US EPA to the Western Oil and Gas Association Reflecting No Denials of Exemptions in Original Primacy Delegation

RECEIVED

JUN 10 1985

DIVISION OF OIL & GAS
BAKERSFIELD

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
215 Fremont Street
San Francisco, Ca. 94105

Mr. Tom Cornwell
Western Oil and Gas Association
727 West 7th Street
Los Angeles, CA 90017

17 MAY 1985

Dear Mr. Cornwell:

The staffs of EPA-Region 9 and the California Division of Oil and Gas (CDOG) have been meeting with members of the Western Oil and Gas Association (WOGA), the California Independent Producers Association (CAIPA), and the Independent Oil Producers Agency (IOPA) to determine how wells injecting specific types of oil field fluids will be regulated under the Underground Injection Control (UIC) program in California. The purpose of this letter is to clarify:

1. how wells injecting filter backwash (diatomaceous earth or multi-media filter backwash), water softener regeneration brine, or air scrubber waste will be classified and regulated under the UIC program in California;

2. the requirements, especially the regulatory deadlines for the submission of permit applications and inventory information for existing wells, for different classes of wells; and

3. which formations identified by CDOG in its primacy application were verified as Underground Sources of Drinking Water (USDW) and exempted and which formations were determined not to be USDWs and did not need to be exempted when primacy for CDOG was approved.

In general, the classification and regulation scheme for wells injecting filter backwash, water softener regeneration brine, or air scrubber wastes under the UIC program in California is:

° wells which inject filter backwash are Class II wells and are regulated by CDOG;

° wells which inject either water softener regeneration brine or air scrubber wastes for the purpose of enhancing oil or natural gas recovery are Class II wells and are regulated by CDOG; and

° wells which inject either water softener regeneration brine or air scrubber wastes for disposal are either Class I or Class V wells and are regulated by EPA.

Attachment 1 provides: a precise statement about these well classifications; a brief description of each of the fluids being injected; clarification of how wells used to inject commingled fluids will be regulated; and a diagram which outlines how wells injecting the different types of fluids will be regulated and by whom in California.

Some, but not all, of the relevant requirements for Class I, II, and III wells under the UIC program implemented in California are:

- Class I wells - for existing wells (wells in operation prior to June 25, 1984) complete permit applications must be submitted to EPA by June 25, 1985 (40 CFR 144.31[c][1] and 147.251[B])

  - for new wells, permits must be in effect prior to any construction (40 CFR 144.11)

- Class II wells - CDOG has been delegated this portion of the UIC program and regulates this class of wells

- Class V wells - for existing wells, a completed inventory form and the required additional information must be submitted to EPA by June 25, 1985 (40 CFR 144.26[d][1] and 147.251[B])

  - for new wells, a complete inventory form and the required additional information should be submitted to EPA prior to construction.

Complete permit applications for existing Class I wells must be submitted to EPA by June 25, 1985. Considering the delays in classifying wells injecting filter backwash, water softener regeneration brine, or air scrubbing waste, allowances may be made for the submission of additional clarifying information after June 25, 1985. However, allowances can only be considered if an application has been been submitted by June 25, 1985 and if the application represents a reasonable and substantial effort toward a complete permit application.

Attachment 2 provides the exact definitions for the different classes of wells and other pertinent definitions in the UIC program. Attachment 3 and 4 are copies of the permit application and Class V Inventory Notification, respectively.

There appears to be some confusion about which formations in oil and gas fields are USDWs and which formations in oil and gas fields are not USDWs under the UIC program. When CDOG submitted its application for the Class II portion of the UIC program, it submitted information about a large number of formations in oil fields to be considered for aquifer exemptions. These included formations which produced oil or gas and formations which did not produce any oil or gas. After reviewing the information from CDOG supporting the aquifer exemptions requests, all formations which were USDWs and produced oil or gas were exempted but only some of the formations which did not produce any oil or gas were granted aquifer exemptions. These latter formations were not exempted because the supporting information demonstrated that they were not USDWs as defined by the UIC program. They yielded water which had a Total Dissolved Solids concentration greater than 10,000 milligrams per liter.

Maps showing the lateral extent of any formation which was exempted can be found in California Oil and Gas Fields (Volumes I, II, and III) and Appendix B of CDOG's primacy application. They are available for review at the EPA office in San Francisco or at any of the CDOG district offices. A list of those formations, which did not produce any oil or gas and were considered for aquifer exemptions, is provided as Attachment 5. A list of those formations, which did not produce any oil or gas and which were USDWs and exempted, is provided as Attachment 6.

I would like to take this opportunity to thank those of your members who met and worked with us to clarify these points in the UIC program. If you have any further questions or need other points of clarification, please call Pete Uribe of my staff at (415) 974-7285.

Sincerely,

for Frank M. Covington, Director
Water Management Division

ATTACHMENTS

1 -	Well Classification and Regulation Scheme	(3 pages)
2 -	UIC Definitions	(3 pages)
3 -	Permit Application	(10 pages)
4 -	Class V Inventory Notification	(7 pages)
5 -	List of Formations Considered for Exemption	(3 pages)
6 -	List of Formations Exempted	(1 page)

cc: M.G. Mefferd, CDOG
J. B. Braden, CAIPA
Les Clark, IOPA
Jim Cornelius, SWRCB
Bill Pfister, CVRWQCB
John Atcheson, EPA HQ

Policy Statement on Well Classifications

Wells which inject filter backwash (diatomaceous or multi-media filter backwash) are Class II wells.

Wells which inject water softener regeneration brine or air scrubber waste are not Class II wells, unless injection is for enhanced recovery, in which case the wells are Class II wells.

Wells which inject water softener regeneration brine or air scrubber waste commingled with other fluids (e.g. produced water or filter backwash) are not Class II wells, unless injection is for enhanced recovery, in which case the wells are Class II wells.

Description of Fluids being Injected

Filter backwash is a fluid with an elevated concentration of suspended solids which were removed from produced water. In general, produced water is passed through either diatomaceous or multi-media filters to remove suspended solids. Periodically, these filters are washed with either fresh or produced water, which has no additives, to remove the suspended solids concentrated in the filter resulting in a filter backwash.

Water softener regeneration brine is a fluid with high concentrations of total dissolved solids, especially calcium, magnesium, and chloride. In general, produced water is softened by passing it through a resin which replaces calcium and magnesium ions in the water with sodium ions. Periodically, the resin in the water softener unit is regenerated with concentrated solutions of sodium chloride, which replaces the calcium and magnesium ions captured on the resin with sodium ions in the solution, yielding a water softener regeneration brine.

Air scrubber waste is sulfur dioxide scrubber blowdown (also commonly known as scrubber liquor) with high concentrations of total dissolved solids (much greater than 10,000 ppm) In general, crude oil is burned for power to produce steam, which is injected to enhance the recovery of extremely heavy crude oil. Air scrubbers are required when the crude oil is burned because Kern County is a Non-Attainment Area for air quality with respect to sulfur dioxide.

Clarifying the Classification of Wells

Injecting Commingled Fluids

Wells injecting only filter backwash or filter backwash commingled with produced water will be Class II wells and will be regulated by CDOG.

Wells injecting fluids with either water softener regeneration brine or air scrubber wastes into oil and gas producing formations for the purpose of enhanced recovery will be Class II wells and will be regulated by CDOG.

Wells injecting only water softener regeneration brine or only air scrubber wastes into non-oil and gas producing formations are not Class II wells and will be directly regulated by the regional office as a Class I or V well.

Wells injecting either water softener regeneration brine or air scrubber wastes together with produced water into non-oil and gas producing formations are not Class II wells and will be directly regulated by the regional office as a Class I or V well.

On the next page is chart which summarizes whether CDOG or EPA is responsible for any given well based on the type of injectate and the injection formation.

FLUID INJECTED	PURPOSE OF INJECTION	INJECTION ZONE	WELL CLASSIFICATION	UIC PERMIT AGENCY
A. Diatomaceous Earth Filter Backwash	Disposal or Enhanced Recovery	Above or into a USDW* Below lowermost USDW	Class II	CDOG
B. 1. Water Softener Regeneration Brine 2. Air Scrubber Waste	Disposal	Above or into a USDW	Class V	EPA**
		Below lowermost USDW	Class I	EPA
	Enhanced Recovery		Class II	CDOG
C. The following wastes commingled with with produced fluids: 1. Water Softener Regeneration Brine 2. Air Scrubber Waste	Disposal	Above or into a USDW	Class V	EPA**
		Below lowermost USDW	Class I	EPA
	Enhanced Recovery		Class II	CDOG

* USDW (Underground Source of Drinking Water)- an aquifer or its portion that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer (see 40 CFR 144.3 for full definition)

** EPA requirements for Class V wells are: submission of inventory information to EPA by operator (40 CFR 144.26) and that EPA assessment of those wells to determine the need for requirements or regulations (40 CFR 146.52(b)) There are currently no permitting requirements for Class V wells under EPA's UIC program. However, EPA has the option to require and the operator has the option to request a permit. EPA cannot preclude the State (CDOG) from regulating these wells under State laws or regulations, so CDOG's existing state program applies.

Region 9 UIC Program Information Sheet

General Information about the Underground Injection Control Program

The Safe Drinking Water Act (SDWA) of 1974, as amended, requires the U.S. Environmental Protection Agency (EPA) to establish a program which provides for the safety of our nation's drinking water. One part of this program, Underground Injection Control (UIC), has been established to prevent contamination of underground sources of drinking water due to improper design, construction and operation of injection wells. Although not recognized, the injection of waste materials is a very common practice. For example, the oil and gas industry operates tens of thousands of wells nationwide which inject brine or brackish wastewater in the production of oil and gas. Other types of injection wells include hazardous waste disposal operations wells, industrial waste disposal wells, municipal disposal operations wells, and nuclear storage and disposal wells.

Underground Sources of Drinking Water

By definition, an Underground Source of Drinking Water (USDW) is an aquifer or a portion of an aquifer:

which supplies any public water system; or

which contains significant quantity of ground water to supply a public water system; and

currently supplies drinking water for human consumption; or

contains fewer than 10,000 mg/l total dissolved solids (TDS) and is not an exempted aquifer.

An aquifer is a geological formation that is capable of yielding a significant amount of water to a well or to a springs. An exempted aquifer is an aquifer that cannot now and will not in the future serve as a source of drinking water, as determined by EPA.

Well Classification

A well is defined as a bored, drilled or driven shaft or dug hole whose depth is greater than the largest surface dimension. There are five classes of injection wells which are regulated by the UIC program. A specific well classification is made by determining the type of fluid to be injected and the geologic area into which the fluid is to be injected. Injection well classes are summarized as follows:

Class I — Class I wells are municipal and industrial disposal wells (including wells used by generators of hazardous waste and owners of hazardous waste management facillities) which inject fluids below the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.

Class II — Class II wells are associated with oil and gas production or liquid hydrocarbon storage. These wells inject fluids which are brought to the surface for the enhanced recovery of oil and natural gas and for the storage of hydrocarbons.

Class III — Class III wells inject fluids for the extraction of minerals and are used in conjunction with solution mining of minerals.

Class IV — Class IV wells are used by generators of hazardous and radioactive wastes. These wells inject into a formation which within one quarter of a mile of the well contains an underground source of drinking water. Class IV wells are prohibited.

Class V — Class V wells are wells which do not meet the criteria listed for classes I through IV. Generally, wells covered under this classification inject non-hazardous fluids into or above formations that contain underground sources of drinking water. Class V wells include the following, but are not limited to these types of wells:

1. air conditioning return flow wells used to return to the supply aquifer the water used for heating or cooling in a heat pump (Questionnaire II);

2. cesspools including multiple dwelling, community or regional cesspools, or other devices that receive wastes which have an open bottom and sometimes have perforated sides. The UIC requirements do not apply to single family residential cesspools nor to non-residential cesspools which receive solely sanitary wastes and have the capacity to serve fewer than 20 persons a day (Questionnaire II);

3. cooling water return flow wells used to inject water previously used for cooling (Questionnaire II);

4. dry wells used for injection of wastes into a subsurface formation (Questionnaire II);

5. drainage wells used to drain surface fluid, primarily storm runoff, into a subsurface formation (Questionnaire II);

6. recharge wells used to replenish the water in an aquifer (Questionnaire II);

7. salt water intrusion barrier wells used to inject water into a fresh water aquifer to prevent the intrusion of of salt water in the fresh water (Questionnaire II);

8. sand backfill and other backfill wells used to inject a mixture of water and sand, mill tailings or other solids into mined out portions of subsurface mines regardless of whether or not it is a radioactive waste (Questionnaire II);

9. septic system wells used to inject the waste of effluent from a multiple dwelling, business establishment, community or regional business establishment septic tank. The UIC requirements do not apply to single family residential septic system wells, nor to non-residential septic system wells which are used solely for the disposal of sanitary wastes and have the capacity to serve fewer than 20 persons a day (Questionnaire II);

10. subsidence control wells (not used for the purpose of oil or natural gas production) used to inject fluids into a non-oil or gas producting zone to reduce or eliminate subsidence associated with the overdraft of fresh water (Questionnaire II);

11. radioactive waste disposal wells other than Class IV (Questionnaire I);

12. injection wells associated with the recovery of geothermal energy for heating, aquaculture, and production of electric power (Questionnaire I);

13. wells used for solution mining of conventional mines such as stopes leaching (Questionnaire I);

14. wells used to inject spent brine into the same formation from which it was withdrawn after extraction of halogens or their salts (Questionnaire I);

15. injection wells used in experimental technologies (Questionnaire I);

16. injection wells used for in situ recovery of lignite, coal, tar sands, and oil shale (Questionnaire II);

17. agricultural drainage wells (Questionnaire II);

18. air scrubber waste disposal wells (except if injection is for enhanced recovery of oil and gas in California); and

19. water softener regeneration brine waste disposal wells (except if injection is for enhanced recovery of oil and gas in California).

Attachment 3

Form Approved. OMB No. 2000-0042. Expires 9-30-86
GSA No.

Form 4 UIC

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

UNDERGROUND INJECTION CONTROL PERMIT APPLICATION

(Collected under the authority of the Safe Drinking Water Act, Sections 1421, 1422, 40 CFR 144)

I. EPA ID NUMBER

	T/A	C
U		

READ ATTACHED INSTRUCTIONS BEFORE STARTING

FOR OFFICIAL USE ONLY

Application approved mo	day	year	Date Received mo	day	year	Permit/Well Number	Comments

II. FACILITY NAME AND ADDRESS			III. OWNER/OPERATOR AND ADDRESS		
Facility Name			Owner/Operator Name		
Street Address			Street Address		
City	State	ZIP Code	City	State	ZIP Code

IV. OWNERSHIP STATUS *(Mark 'x')*

☐ A. Federal ☐ B. State ☐ C. Private

☐ D. Public ☐ E. Other *(Explain)*

V. SIC CODES

VI. WELL STATUS *(Mark 'x')*

☐ A. Operating	Date Started mo	day	year	☐ B. Modification/Conversion	☐ C. Proposed

VII. TYPE OF PERMIT REQUESTED *(Mark 'x' and specify if required)*

☐ A. Individual ☐ B. Area	Number of Existing wells	Number of Proposed wells	Name(s) of field(s) or project(s)

VIII. CLASS AND TYPE OF WELL *(see reverse)*

A. Class(es) *(enter code(s))*	B. Type(s) *(enter code(s))*	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)

IX. LOCATION OF WELL(S) OR APPROXIMATE CENTER OF FIELD OR PROJECT

C I	A. Latitude Deg	Min	Sec	B. Longitude Deg	Min	Sec	Township and Range Twsp	Range	Sec	¼ Sec	Feet from	Line	Feet from	Line

X. INDIAN LANDS *(Mark 'x')*

☐ Yes ☐ No

XI. ATTACHMENTS

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

FOR CLASSES I, II, III (and other classes) complete and submit on separate sheet(s) Attachments A — U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application:

XII. CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations. (Ref. CFR 122.6)

A. Name and Title *(Type or Print)*	B. Phone No. *(Area Code and No.)*
C. Signature	D. Date Signed

EPA Form 7520-6 (12-83)

Continued on Reverse

Well Class and Type Codes

Class I	Wells used to inject waste below the deepest underground source of drinking water.
Type "I"	Nonhazardous industrial disposal well
"M"	Nonhazardous municipal disposal well
"W"	Hazardous waste disposal well injecting below USDWs
"X"	Other Class I wells (not included in Type "I," "M," or "W")
Class II	Oil and gas production and storage related injection wells.
Type "D"	Produced fluid disposal well
"R"	Enhanced recovery well
"H"	Hydrocarbonn storage well (excluding natural gas)
"X"	Other Class II wells (not included in Type "D," "R," or "H")
Class III	Special process injection wells.
Type "G"	Solution mining well
"S"	Sulfur mining well by Frasch process
"U"	Uranium mining well (excluding solution mining of conventional mines)
"X"	Other Class III wells (not included in Type "G," "S," or "U")
Other Classes	Wells not included in classes above.
	Class V wells which may be permitted under §144.12
	Wells not currently classified as Class I, II, III, or V.

INSTRUCTIONS - Form 4 - Underground Injection Control (UIC) Permit Application

Form 4 must be completed by all owners or operators of Class I, II, and III injection wells and others who may be directed to apply for a UIC permit by the Director.

I. EPA I.D. NUMBER - Fill in your EPA Identification Number. If you do not have a number, leave blank.

II. FACILITY NAME AND ADDRESS - Name of well, well field or company and address.

III. OWNER/OPERATOR NAME AND ADDRESS - Name and address of owner/operator of well or well field.

IV. OWNERSHIP STATUS - Mark the appropriate box to indicate the type of ownership.

V. SIC CODES - List at least one and no more than four Standard Industrial Codes (SIC) that best describe the nature of the business in order of priority.

VI. WELL STATUS - Mark Box A if the well(s) were operating as injection wells on the effective date of the UIC Program for the State. Mark Box B if the well(s) existed on the effective date of the UIC Program for the State but were not utilized for injection. Box C should be marked if the application is for an underground injection project not constructed or not completed by the effective date of the UIC Program for the State.

VII. TYPE OF PERMIT - Mark "Individual" or "Area" to indicate the type of permit desired. Note that area permits are at the discretion of the Director and that wells covered by an area permit must be at one site, under the control of one person and do not inject hazardous waste. If an area permit is requested the number of wells to be included in the permit must be specified and the wells described and identified by location. If the area has a commonly used name, such as the "Jay Field", submit the name in the space provided. In the case of a project or field which crosses State lines, it may be possible to consider an area permit if EPA has jurisdiction in both States. Each such case will be considered individually, if the owner/operator elects to seek an area permit.

VIII. CLASS AND TYPE OF WELL - Enter in these two positions the Class and type of injection well for which a permit is requested. Use the most pertinent code selected from the list on the reverse side of Form 4. When selecting type X please explain in the space provided.

IX. LOCATION OF WELL - Enter the latitude and longitude of the existing or proposed well expressed in degrees, minutes, and seconds or the location by township, and range, and section, as required by 40 CFR 146. If an area permit is being requested, give the latitude and longitude of the approximate center of the area.

X. INDIAN LANDS - Place an "X" in the box if any part of the facility is located on Indian lands.

XI. ATTACHMENTS - Note that information requirements vary depending on the injection well class and status. Attachments for Class I, II, and III are described on pages 3-7 of this document and listed by Class on page 8. Place EPA ID number in the upper right hand corner of each page.

XII. CERTIFICATION - All permit applications (except Class II) must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, and by a principal executive or ranking elected official for a public agency. For Class II, the person described above should sign, or a representative duly authorized in writing.

Attachments to be submitted with permit application for Class I, II, III and other wells.

A. AREA OF REVIEW METHODS - Give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation). The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.

B. MAPS OF WELLS/AREA AND AREA OF REVIEW - Submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste, treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:

Class I

The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells and other pertinent surface features, including residences and roads, and faults, if known or suspected. Only information of public record is required to be included on this map;

Class II

In addition to requirements for Class I, include pertinent information known to the applicant. Requirement does not apply to existing Class II wells;

Class III

In addition to requirements for Class I, include public water systems and pertinent information known to the applicant.

C. CORRECTIVE ACTION PLAN AND WELL DATA - Submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone.

Such data shall include the following:

Class I

A description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. In the case of new injection wells, include the corrective action proposed to be taken by the applicant under 40 CFR 144.55.

Class II

In addition to requirements for Class I, in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. This requirement does not apply to existing Class II wells.

Class III

In addition to requirements for Class I, the corrective action proposed under 40 CFR 144.55 for all Class III wells.

D. MAPS AND CROSS SECTIONS OF USDW'S - Submit maps and cross sections indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

E. NAME AND DEPTH OF USDW'S (CLASS II) - For Class II wells, submit geologic name, and depth to bottom of all underground sources of drinking water which may be affected by the injection.

F. MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA - Submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross sections illustrating the regional geologic setting. (Does not apply to Class II wells.)

G. GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (CLASS II) - For Class II wells, submit appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and fracture pressure.

H. OPERATING DATA - Submit the following proposed operating data for each well (including all those to be covered by area permits): (1) average and maximum daily rate and volume of the fluids to be injected; (2) average and maximum injection pressure; (3) nature of annulus fluid; (4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

I. FORMATION TESTING PROGRAM - Describe the proposed formation testing program. For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the program must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the formation is not water bearing. (Does not apply to existing Class III wells or projects.)

J. STIMULATION PROGRAM - Outline any proposed stimulation program.

K. INJECTION PROCEDURES - Describe the proposed injection procedures including pump, surge, tank, etc.

L. CONSTRUCTION PROCEDURES - Discuss the construction procedures (according to §146.12(b) for Class I) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring programs, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to a packer for Class I.)

M. CONSTRUCTION DETAILS - Submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

N. CHANGES IN INJECTED FLUID - Discuss expected changes in pressure, native fluid displacement, and direction of movement of injected fluid. (Class II and III wells only.)

O. PLANS FOR WELL FAILURES - Outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or well failures, so as to prevent migration of fluids into any USDW.

P. MONITORING PROGRAM - Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and a discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Q. PLUGGING AND ABANDONMENT PLAN - Submit a plan for plugging and abandonment of the well including: (1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used; (2) describe the type, grade, and quantity of cement to be used; and (3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDW's.

R. NECESSARY RESOURCES - Submit evidence such as a surety bond or financial statement to verify that the resources necessary to close, plug or abandon the well are available.

S. AQUIFER EXEMPTIONS - If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon producing, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR 144.7 and 146.04.

T. EXISTING EPA PERMITS - List program and permit number of any existing EPA permits, for example, NPDES, PSD, RCRA, etc.

U. DESCRIPTION OF BUSINESS - Give a brief description of the nature of the business.

Attachments to Permit Application

Class	Attachments
I	
new well	A, B, C, D, F, H - S, U
existing	A, B, C, D, F, H - U
II	
new well	A, B, C, E, G, H, M, Q, R; optional - I, J, K, N, O, P, U
existing	A, E, G, H, M, Q, R - U; optional - J, K, N, O, P, Q
III	
new well	A, B, C, D, F, H, I, J, K, M - S, U
existing	A, B, C, D, F, H, J, K, M - U
Other Classes	To be specified by the permitting authority

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
215 Fremont Street
San Francisco, Ca. 94105

Re: Information on Class V Injection Wells for Underground Injection Control Program of the Environmental Protection Agency (EPA)

To whom it may concern:

As required by EPA regulations [Title 40 of the Code of Federal Regulations (CFR), Section 144.26], owners and operators of all Class V injection wells in American Samoa, Arizona, California, Hawaii, Nevada, and the Trust Territories must submit information about these wells to the EPA by June 25, 1985.

A well is defined as a "bored, drilled or driven shaft, or dug hole, whose depth is greater than the largest surface dimension (40 CFR 146.3)." Class V wells include a diverse group of wells used for residential, municipal or industrial purposes. A more detailed list of the types of Class V wells is enclosed (see attachment A).

Please provide EPA, Region 9 with information regarding Class V wells within your jursidiction or operation. Include information on all injection wells located in the states mentioned above. Questionnaire I should be completed for radioactive waste disposal wells, geothermal energy recovery wells, brine return flow wells, municipal and industrial disposal wells (other than those classified as Class I as defined in the enclosed attachment), air scrubbers waste disposal wells (except if injection is for enhanced recovery of oil and gas in California), water softener regeneration brine waste disposal wells (except if injection is for enhanced recovery of oil and gas in California), wells used in experimental technologies and solution mining. Questionnaire II should be completed for all other well types of Class V wells.

Please complete either or both of these questionnaires to the best of your ability and return the information in the self-addressed envelope by June 25, 1985. If you do not have any or know of any Class V wells, please note on the questionnaires that you have no or know of no Class V wells. Your cooperation in this effort will be greatly appreciated. This information could result in the prevention or improvement of a water quality problem in the ground water in your area. If you have any questions, please contact Jayne Carlin of my staff at (415) 974-7116.

Sincerely,

Pete Uribe, Chief
Underground Injection Control Section
Water Management Division

Enclosures

QUESTIONNAIRE I

1. Facility Name: ____________________

Facility Address: ____________________

(Include County) ____________________

Telephone Number: ( ) ____________________

Name of Legal Contact: ____________________

Address of Legal Contact: ____________________

____

Name of Owner: ____________________

Address of Owner: ____________________

____

If subsidiary, name of parent co.: ____________________

Address of parent company: ____________________

____

2. Ownership: ____ Private ____ Public ____ State ____ Federal ____ Indian Lands

3. Provide general information about the well(s):

Name or Identification of the well	Exact Location of Well*	Type of Well**	Status of Well***

****

* Exact Location of Well by Latitude and longitude to the nearest second; or by Township, Range, Section, Quarter-Sections; or by street address if located at a private address.

** For assistance in determining type of well, see Attachment A - pages 2 and 3.

***Codes for Well Status:
UC = under construction
AC = active
TA = temporarily plugged (no longer used but not plugged)
PA = permanently plugged & abandoned and approved by state

4. Explain the construction features of the well(s):

Name or Identification of Well	Date of Completion of Well	Casing and Cementing Records	Total Depth of Well	Average and Maximum Injection Pressure at Well Head	Date of Last Mechanical Integrity Test*

5. List the nature and volume of the fluids injected into the well:

Name or Identification of Well	Description of Injected Fluids**	Identification and Depth of Formation into which well is injected	Average and Maximum Injection Rate

6. Are any of the following fluids injected into the well(s)? If so, what is the volume and frequency of the injected fluid?

Washdown:

Stormwater:

Spills:

7. Identify and discuss each location, purpose, frequency of use and depth of all disposal wells on the site:

____

____

____

8. Name and Title of Preparer of Questionnaire ______________________________

* Liquid and gas pressure tests, annulus pressure tests etc. which test for leaks in casing, tubing or packer or significant movement into an underground source of drinking water through vertical channels adjacent to injection well bore.

** Include in your answer the process or business that produces the fluid and the chemical constituents of the fluid.

QUESTIONNAIRE II

Facility Name: ______________________________

Facility Address: ______________________________

(Include County) ______________________________

Telephone Number: (   ) ______________________________

Name of Legal Contact: ______________________________

Address of Legal Contact: ______________________________

____

Name of Owner: ______________________________

Address of Owner: ______________________________

____

Ownership: ____ Private ____ Public ____ State ____ Federal ____ Indian Lands

Number of Well(s)	Type of Well(s)*	Location of Well(s)	Status of Well(s)**

Name and Title of Preparer of Questionnaire ______________________________

****

* For assistance in determining type of well, see Attachment A - page 2 and 3.

**Codes for Well Status:
UC = under construction   TA = temporarily abandoned (no longer used but not plugged)
AC = active   PA = permanently plugged & abandoned and approved by state

ATTACHMENT A

Region 9 UIC Program Information Sheet

General Information about the Underground Injection Control Program

The Safe Drinking Water Act (SDWA) of 1974, as amended, requires the U.S. Environmental Protection Agency (EPA) to establish a program which provides for the safety of our nation's drinking water. One part of this program, Underground Injection Control (UIC), has been established to prevent contamination of underground sources of drinking water due to improper design, construction and operation of injection wells. Although not recognized, the injection of waste materials is a very common practice. For example, the oil and gas industry operates tens of thousands of wells nationwide which inject brine or brackish wastewater in the production of oil and gas. Other types of injection wells include hazardous waste disposal operations wells, industrial waste disposal wells, municipal disposal operations wells, and nuclear storage and disposal wells.

Underground Sources of Drinking Water

By definition, an Underground Source of Drinking Water (USDW) is an aquifer or a portion of an aquifer:

which supplies any public water system; or

which contains significant quantity of ground water to supply a public water system; and

currently supplies drinking water for human consumption; or

contains fewer than 10,000 mg/l total dissolved solids (TDS) and is not an exempted aquifer.

An aquifer is a geological formation that is capable of yielding a significant amount of water to a well or to a springs. An exempted aquifer is an aquifer that cannot now and will not in the future serve as a source of drinking water, as determined by EPA.

Well Classification

A well is defined as a bored, drilled or driven shaft or dug hole whose depth is greater than the largest surface dimension. There are five classes of injection wells which are regulated by the UIC program. A specific well classification is made by determining the type of fluid to be injected and the geologic area into which the fluid is to be injected. Injection well classes are summarized as follows:

Class I — Class I wells are municipal and industrial disposal wells (including wells used by generators of hazardous waste and owners of hazardous waste management facillities) which inject fluids below the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.

Class II — Class II wells are associated with oil and gas production or liquid hydrocarbon storage. These wells inject fluids which are brought to the surface for the enhanced recovery of oil and natural gas and for the storage of hydrocarbons.

Class III — Class III wells inject fluids for the extraction of minerals and are used in conjunction with solution mining of minerals.

Class IV — Class IV wells are used by generators of hazardous and radioactive wastes. These wells inject into a formation which within one quarter of a mile of the well contains an underground source of drinking water. Class IV wells are prohibited.

Class V — Class V wells are wells which do not meet the criteria listed for classes I through IV. Generally, wells covered under this classification inject non-hazardous fluids into or above formations that contain underground sources of drinking water. Class V wells include the following, but are not limited to these types of wells:

1. air conditioning return flow wells used to return to the supply aquifer the water used for heating or cooling in a heat pump (Questionnaire II);

2. cesspools including multiple dwelling, community or regional cesspools, or other devices that receive wastes which have an open bottom and sometimes have perforated sides. The UIC requirements do not apply to single family residential cesspools nor to non-residential cesspools which receive solely sanitary wastes and have the capacity to serve fewer than 20 persons a day (Questionnaire II);

3. cooling water return flow wells used to inject water previously used for cooling (Questionnaire II);

4. dry wells used for injection of wastes into a subsurface formation (Questionnaire II);

5. drainage wells used to drain surface fluid, primarily storm runoff, into a subsurface formation (Questionnaire II);

6. recharge wells used to replenish the water in an aquifer (Questionnaire II);

7. salt water intrusion barrier wells used to inject water into a fresh water aquifer to prevent the intrusion of of salt water in the fresh water (Questionnaire II);

8. sand backfill and other backfill wells used to inject a mixture of water and sand, mill tailings or other solids into mined out portions of subsurface mines regardless of whether or not it is a radioactive waste (Questionnaire II);

9. septic system wells used to inject the waste of effluent from a multiple dwelling, business establishment, community or regional business establishment septic tank. The UIC requirements do not apply to single family residential septic system wells, nor to non-residential septic system wells which are used solely for the disposal of sanitary wastes and have the capacity to serve fewer than 20 persons a day (Questionnaire II);

10. subsidence control wells (not used for the purpose of oil or natural gas production) used to inject fluids into a non-oil or gas producting zone to reduce or eliminate subsidence associated with the overdraft of fresh water (Questionnaire II);

11. radioactive waste disposal wells other than Class IV (Questionnaire I);

12. injection wells associated with the recovery of geothermal energy for heating, aquaculture, and production of electric power (Questionnaire I);

13. wells used for solution mining of conventional mines such as stopes leaching (Questionnaire I);

14. wells used to inject spent brine into the same formation from which it was withdrawn after extraction of halogens or their salts (Questionnaire I);

15. injection wells used in experimental technologies (Questionnaire I);

16. injection wells used for in situ recovery of lignite, coal, tar sands, and oil shale (Questionnaire II);

17. agricultural drainage wells (Questionnaire II);

18. air scrubber waste disposal wells (except if injection is for enhanced recovery of oil and gas in California); and

19. water softener regeneration brine waste disposal wells (except if injection is for enhanced recovery of oil and gas in California).

NONHYDROCARBON-PRODUCING ZONE INJECTION DATA

DIST.	FIELD	FORMATION & ZONE	TDS OF ZONE WATER PRIOR TO INJECTION	TDS OF INJECTED WATER	VOLUME INJECTED (Barrels)	INJECTI STARTEI
1	Belmont Offshore	Repetto	30,800			
1	Huntington Beach	Lakewood				
		Alpha 1	37,200			
		Alpha 2	12,500			
1	Sawtelle	Puente	25,500			
1	Seal Beach	Repetto	29,700			
		Recent Sands	30,200			
1	Wilmington	Gaspur	28,200			
1	"	River Gravels	30,800			
2	Ramona	Pico	5,000	15,300 ppm NaCl	1,793,000	6/51
2	South Tapo Canyon	Pico	1,900 ppm NaCl	600 ppm NaCl	1,903,000	1/48
2	Oat Mountain	Undiff.	4,800	23,800 ppm NaCl	91,000	4/56
2	Simi	Sespe	4,300	25,500 ppm NaCl	695,000	6/48
3	Guadalupe	Knoxville	30,500			
3	Lompoc	Lospe	119,000			
3	Lompoc	Knoxville	30,500			
3	Russell Ranch	Branch Canyon	13,000			
3	San Ardo	Santa Margarita	3,700	5,600	81,800,000	11/66
3	"	Monterey "D" Sand	4,600	5,600	13,795,000	7/59
3	"	Monterey "E" Sand	6,400	5,600	6,057,000	3/68
3	Santa Maria Valley	Lospe-Franciscan	119,000			
3	Monroe Swell	Santa Margarita	3,700 ppm NaCl	9,600	?	1981
3	Point Conception	Camino Cielo	26,200			
3	Guadalupe	Franciscan	30,500			
4	Bellevue	Etchegoin	26,500 (Analysis from adjacent field)			
4	Bellevue, West	Tulare	12,000*			
4	"	Etchegoin	26,500 (Analysis from adjacent field)			
4	Blackwell's Corner	Tumey	2,100 -2,600*	29,000 ppm NaCl	400,000	5/75
4	Buena Vista	Tulare	9,200	5,300-36,500	50,798,000	11/72
4	Cal Canal	Tulare-San Joaquin	Excess of 10,000*	22,000	537,000	5/79
4	Canfield Ranch	Etchegoin	≈12,800-26,500 (Analysis from adjacent fields)			

*"Σ" log calculation

17 MAY 198?

Attachment 5
Page 1 of 3

DIST.	FIELD	FORMATION & ZONE	TDS OF ZONE WATER PRIOR TO INJECTION	TDS OF INJECTED WATER	VOLUME INJECTED (Barrels)	INJECT STARTE
4	North Coles Levee	Tulare	12,900			
4	"	San Joaquin	40,000-45,600			
4	"	Etchegoin	30,100			
4	South Coles Levee	Tulare	12,000-13,300			
4	"	San Joaquin	12,000-16,900			
4	Greeley	Etchegoin	26,500			
4	Kern Bluff	Kern River	≈ 400- 900 (From Kern River Field)	600	551,500	7/80
4	"	Vedder	≈ 7,800-16,100 "	11,700-213,000	4,099,000	3/80
4	Kern Front	Santa Margarita	2,300	1,100		9/75
4	Kern River	Chanac	238- 925	374- 865	1,071,000	6/77
4	"	Santa Margarita	600- 2,600	475- 16,200	154,994,000	9/73
4	"	Vedder	7,800-16,200		33,204,000	
4	Lakeside	San Joaquin	21,500			
4	Los Lobos	Tulare	33,300*			
4	Midway-Sunset	Alluvium	No water	3,600- 25,700		7/59
4	Mount Poso	Walker	2,800*	830- 1,440	22,632,000	9/75
4	Mountain View	Kern River	4,660*	1,200- 3,800	3,681,000	12/65
4	Pleito	Chanac & Kern River	7,900-11,800	12,800-30,800	889,000	8/74
4	Poso Creek	Vedder	12,500			
4	Rio Viejo	San Joaquin	21,000*			
4	Rosedale	Etchegoin	26,500 (Analysis from adjacent field)			
4	Round Mountain	Olcese	2,700	1,337- 1,965	29,797,000	7/74
4	"	Walker	1,930	1,600 - 2,100	203,319,000	8/72
4	Seventh Standard	Etchegoin	17,100-30,000 (NaCl only)			
4	Strand	Etchegoin	8,600 (NaCl only)	16,500-25,600 (NaCl only)	1,195,000	7/62
4	"	San Joaquin	33,400			
4	Ten Section	San Joaquin	12,900			
5	Burrel	Santa Margarita	35,000 (Analysis from Helm field)			
5	"	Tulare-Kern River	20,500 (Analysis from S.E. Burrel field)			
5	Southeast Burrel	Tulare-Kern River	20,500			
5	Coalinga	Santa Margarita	8,244	3,100- 3,500	(145,000,000	2/63
5	"	Etchegoin-Jacalitos	2,650- 2,900	2,650-2,700	(	2/63
5	Gill Ranch Gas	Zilch	14,500			

*"E" log calculation

Attachment 5
Page 2 of 3

DIST.	FIELD	FORMATION & ZONE	TDS OF ZONE WATER PRIOR TO INJECTION	TDS OF INJECTED WATER	VOLUME INJECTED (Barrels)	INJECT STARTE
5	Guijarral Hills	Etchegoin-Jacalitos	9,400	20,500	931,000	4/67
5	Helm	Santa Margarita	35,900		(143,000,000	
5	"	Tulare-Kern River	5,100-23,900	11,600-43,400	(	12/52
5	Jacalitos	Etchegoin-Jacalitos	33,749	5,500 (Cl only)	180,000	10/78
5	Kettleman North Dome	San Joaquin-Etchegoin	10,000	23,800-31,200	48,608,000	8/64
5	Raisin City	Pliocene	12,800-34,000			
5	"	Santa Margarita	35,000	(Analysis from Helm field)		
5	Riverdale	Pliocene	4,788-16,200		(72,626,000	7/57
5	"	Santa Margarita	35,900	(Analysis from Helm field)	(	
5	San Joaquin	Pliocene	17,100			
5	San Joaquin, Northwest	Basal McClure	90,000	18,500	Test well-no injection	
5	Turk Anticline	San Joaquin	3,700- 4,440	9,500- 9,800	466,000	11/76
6	Bunker Gas	Undiff.	1,200	11,000	388,000	1/75
6	Grimes Gas	Kione	16,800			
6	Grimes, West, Gas	Kione	34,000*			
6	La Honda (South Area)	Vaqueros	41,000			
6	Lathrop Gas	Starkey	15,400*			
6	River Break Gas	Capay	6,900*	7,000	93,000	7/75
6	Roberts Island Gas	Undiff.	18,000*			
6	Sutter Buttes Gas	Kione	2,500	4,600-23,000	644,000	7/77
6	Union Island Gas	Mokelumne River	5,000-6,000*	7,800	471,000	7/77
6	Wild Goose	Undiff.	2,800-5,000*	21,400	823,000	11/69

17 MAY 1985

Attachment 6
Page 3 of 3

* "E" log calculation

Attachment 2

Exempted 1425 Demonstration Aquifers

All oil and gas producing aquifers identified in Volumes I, II, and III of the California Oil and Gas Fields submitted in the 1425 Demonstration dated April 20, 1981 are exempted.

In addition, the following aquifers are also exempted.

DISTRICT	FIELD	FORMATION/ZONE
2	Ramona	Pico
2	Oat Mountain	Undiff.
2	South Tapo Canyon	Pico
2	Simi	Sespe
2	San Ardo	Santa Margarita
3	San Ardo	Monterey "D" Sand
3	San Ardo	Monterey "E" Sand
3	Monroe Swell	Santa Margarita
4	Blackwell's Corner	Tumey
4	Kern Bluff	Kern River
4	Kern Front	Santa Margarita
4	Kern River	Chanac
4	Kern River	Santa Margarita
4	Mount Poso	Walker
4	Round Mountain	Olcese
4	Round Mountain	Walker
4	Buena Vista	Tulare
4	Kern Bluff	Vedder
4	Kern River	Vedder*
4	Mountain View	Kern River
4	Pleito	Chanac
4	Pleito	Kern River
4	Poso Creek	Santa Margarita
5	Coalinga	Santa Margarita
5	Coalinga	Etchegoin-Jacalitos
5	Guijarral Hills	Etchegoin-Jacalitos*
5	Helm	Tulare-Kern River
5	Riverdale	Pliocene
5	Turk Anticline	San Joaquin
6	Sutter Buttes Gas	Kione*
6	Bunker Gas	Undiff.
6	Wild Goose	Undiff.

*Oil and/or gas producing